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Technical Report

Inventory of Missouri's Estimated Greenhouse Gas Emissions in 1990

Prepared by

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RECYCLED PAPER

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Greenhouse Gas Emission Trends and Projections for Missouri, 1990 – 2015

Technical Report

August 1999

Prepared by: John Noller, Energy Specialist

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Missouri Department of Natural Resources
Division of Energy
Jefferson City, Missouri
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Preface

Preface

Several previous studies and reports serve as the background for this report on state greenhouse gas (GHG) trends and projections. In 1989, by concurrent resolution, the Missouri legislature established the Commission on Global Climate Change and Ozone Depletion. The Commission compiled information on sources of greenhouse gas (GHG) emissions in the state, analyzed possible local scenarios of climate change and identified adverse consequences for the state should climate change occur.[1]

The Missouri Commission listed adaptation measures as well as policy options to "reduce our contribution to global climate change." The Commission advocated an approach that emphasizes policies with benefits *in addition to* their impact on greenhouse gas emissions. The Commission stated that:

> *…each option in this report [is proposed] because good environmental stewardship and energy efficiency will make Missouri stronger economically, improve our flexibility in the face of uncertain international energy markets, and fulfill our environmental responsibilities. These benefits prevail regardless of whether Missouri experiences substantial or subtle climate changes.*[2]

A similar approach to climate change policy was advocated in a study by a Missouri Department of Natural Resources Institute sponsored by the Missouri Department of Natural Resources in 1992.[3] The Institute's study recommended focusing on "no-regrets" policies that had concomitant economic and environmental benefits.

In 1996, the Division of Energy, Department of Natural Resources published an *Inventory of Missouri's Estimated Greenhouse Gas Emissions in 1990*. The report, funded in part through a grant from the U.S. Environmental Protection Agency (USEPA), provided a more detailed analysis of emissions sources than that published by the Missouri Commission.

This technical report on trends and projections was funded in part by a second grant from USEPA to the Division of Energy. The estimates and projections in this study provide a baseline estimate for the purpose of monitoring changes in the state's greenhouse gas and guiding the formulation of policies to reduce the state's greenhouse gas emissions. The Division of Energy will also produce a second report under the grant. The second report will identify state policies and action options to reduce greenhouse gas emissions in Missouri and will analyze the economic and environmental benefits and costs of these options.

Chapter 1 updates previous estimates of Missouri's 1990 baseline GHG emissions. The report focuses on four greenhouse gases in Missouri - carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O) and perfluorocabons (PFCs). Anthropogenic emissions of these four gases equaled approximately 148 Million Tons Carbon Dioxide Equivalent (MTCDE)[4] in 1990. About 75 percent of these emissions (111 million tons) were CO_2 emissions from fossil fuel use.

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[1] Missouri Commission on Global Climate Change and Ozone Depletion, *Report*, 1991. Jefferson City, Missouri.

[2] Missouri Commission on Global Climate Change and Ozone Depletion, *Report*, 1991. Jefferson City, Missouri, p. 66.

[3] DNR Institute 1991-92, *The Effects of Global Climate Change*, 1992. Jefferson City, Missouri, p. 22.

[4] The concept of carbon dioxide equivalent units is explained in Chapter 1.

Chapter 1 also provides an overview of the report's estimates of state GHG trends (1990 to 1996) and projections (1996 to 2015). The report estimates that between 1990 and 1996, gross emissions of the four greenhouse gases from all sources increased by about 20 million tons, from about 148 million tons (MTCDE) to 168 million tons (MTCDE).

Trends in CO_2 emissions from fossil fuel combustion are analyzed in Chapter 2, and trends in GHG emissions from other sources are analyzed in Chapter 5. Chapter 2 finds that CO_2 emissions from fossil fuel combustion increased by about 22 million tons between 1990 and 1996. In 1996, about 80% of gross GHG emissions (133 million tons) were CO_2 emissions from fossil fuel use. Chapter 5 finds that methane emissions increased by nearly 2 million tons MTCDE between 1990 and 1996, but this increase in methane emissions was more than offset by a decrease in PFC emissions of nearly 4 million tons MTCDE.

Rather than provide a single estimate for future GHG emissions, the report provides a range of estimates based on different projection methods and scenarios. All projections assume "business as usual," that is, no new policies to limit or reduce GHG emissions.

Chapter 3 projects future CO_2 emissions from fossil fuel combustion by utilities and Chapter 4 projects CO_2 emissions from fossil fuel combustion in other sectors. The resulting projections for gross CO_2 emissions from energy use in 2015 range from 154 to 170 million tons, with several projections falling into a midrange estimate of 161-163 million tons MTCDE.

Chapter 5 estimates GHG emissions from a variety of sources other than energy use. The chapter estimates that GHG emissions from some sources will decrease and others will increase between 1996 and 2015, but the total will be about the same in 2015 as in 1996, 34 to 35 million tons MTCDE.

The estimates in Chapters 2 through 5 all deal with gross GHG emissions from energy use and other sources. Chapter 6 provides estimates of net GHG emissions. The estimate of net emissions takes into account the effect of biomass growth in Missouri's forests, which cover nearly a third of the state, as well as land use changes. As explained in Chapter 6, the net effect of these factors in 1990 was to sequester about 20 million tons of carbon dioxide. Chapter 6 projects that annual carbon sequestration will decline over time, but discusses possible errors in the estimate due to limitations in the way that available models for estimating net sequestration deal with increased removal of forest products.

The analysis was completed by staff of the Division of Energy, Missouri Department of Natural Resources. Trend estimates were calculated in accordance with methodology specified in the *State Workbook: Methodologies for Estimating Greenhouse Gas Emissions*, published by the State and Local Outreach Program of USEPA's Climate Change Division. USEPA and the Energy Information Administration (EIA) of the U.S. Department of Energy have taken a lead role in developing methodology and sponsoring research on U.S. emissions and have published national emissions inventories. Staff in both agencies provided invaluable technical assistance to this project.

The State and Local Outreach Program has provided funding for greenhouse gas inventories by a number of states, including Missouri. Because these state inventories are based on 1990 data and use *State Workbook* methodology, it is possible to compare their results.

The estimation procedures used in the Missouri inventory, other state inventories and national inventories published by USEPA and EIA are based on an international research effort. The international effort has involved numerous U.S. researchers and has evolved during the past decade under the auspices of the Intergovernmental Panel on Climate Change (IPCC).[5] U.S. researchers have also been involved in this effort through U.S. national commitments under the Framework Convention on Climate Change.[6]

[5] In 1988, the Intergovernmental Panel on Climate Change (IPCC) was jointly established by the United Nations Environment Program and the World Meteorological Organization in order to assess scientific information related to climate change issues. Under IPCC auspices, technical experts from over 50 countries and the Organization for Economic Cooperation and Development developed methods for estimating emissions and uptake of greenhouse gases, culminating publication of the *IPCC Guidelines for National Greenhouse Gas Inventories: Vol. 1-3* (IPCC, 1994).

[6] The US. was a signatory of the Framework Convention on Climate Change, which came into force on March 21, 1994. The Framework Convention commits signatories to develop national inventories of anthropogenic emissions of greenhouse gases. Accordingly, the U.S. government published the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1993* (USEPA 1994) and the *U.S. Climate Action Report* (U.S. Government, 1994).

Acknowledgments

Acknowledgments

This study was funded in part by a grant from the State and Local Outreach Program of the Climate Change Division of the U.S. Environmental Protection Agency (USEPA) and will be followed by a second report that will analyze the economic and environmental benefits and costs of state policies and action options to reduce emissions.

Anita Randolph, Director of the Division of Energy, made this project possible through her support and guidance. James Muench, Gerald Hirsch, Lesley Cryderman and Trish Whittle of the Division of Energy worked many long hours refining the concept, style and layout of the report.

The estimates and analysis in this study could not have been accomplished without the help of staff from a number of other state and federal agencies, who provided data and assistance in analyzing specific emissions sources. However, responsibility for the accuracy of the results rests with the Division of Energy.

Assistance was received from numerous Missouri state agencies, including:

- Missouri Department of Natural Resources, Division of Geology and Land Survey;
- Missouri Department of Natural Resources, Division of Environmental Quality, Air Pollution Control Program and Solid Waste Management Program;
- Missouri Highway and Transportation Department, Division of Planning;
- Missouri Department of Agriculture, Missouri Agricultural Statistics Service;
- Missouri Department of Conservation, Forestry Service;
- Missouri Department of Economic Development, Economic Development Programs and Public Service Commission;
- Missouri Department of Revenue, Division of Motor Vehicles and Tax Administration Bureau;
- University of Missouri-Columbia: Agricultural Extension Service, Fertilizer Control Service, Agricultural Experiment Station, School of Natural Resources, Food and Agriculture Policy Research Institute, Office of Social and Economic and Data Analysis (OSEDA), and School of Business and Public Administration Research Center;
- Missouri State Demographer; and
- Missouri State Library.

Assistance was also received from numerous federal and non-government sources. Federal agencies that provided data and methodological assistance include USEPA; U.S. Department of Agriculture, National Forest Service, North Central Forest Experiment Station; and U.S. Department of Energy (USDOE) Energy Information Administration (EIA). EIA staff were generous in providing unpublished data and providing critiques of methodology and data quality. ICF, a private firm contracted by USEPA to write the *State Manual* and to offer assistance to states pursuing inventory studies, was also consulted and provided data for the estimates. Other non-government sources providing assistance include Springfield Municipal Utilities and Noranda Aluminum, Inc.

Greenhouse Gas Emission Trends and Projections for Missouri, 1990-2015 Technical Report

Chapter 1

Introduction and Overview

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Chapter 1: Introduction & Overview

For several decades, atmospheric scientists and climatologists have been concerned that human activities such as energy use may increase the concentration of greenhouse gases in the atmosphere, enhancing the "greenhouse effect" and thereby altering temperature and other determinants of global climate.[1]

The greenhouse effect itself is well established, but it is difficult to determine whether global climate change is actually taking place and impossible to predict with certainty the timing, magnitude or regional distribution of climatic change that would result from the greenhouse effect. However, a number of supercomputer-based climate models have been developed in recent years to delineate the complex interaction of greenhouse gases and other factors that affect climate.

Many of these models project that increased concentrations of greenhouse gases will result in increased average temperatures by 2 to 4°C and changes in patterns of precipitation in most regions of the world. Natural systems could be disrupted, injuring forests, fisheries, coastal zones, agriculture, water resources, energy demand and supply, air quality, and human health.

Over the past dozen years, concern over the possible consequences of these anthropogenic (human-origin) greenhouse gas (GHG) emissions and their possible consequences has migrated from a relatively small scientific community to the forum of state, national and international policy makers. For example, about 25 states, including Missouri, have completed inventories of their 1990 GHG emissions, and several states, including Missouri, have undertaken projects to analyze possible actions to reduce GHG emissions.

Most of the state inventories, including Missouri's, follow methodological guidelines provided by the U.S. Environmental Protection Agency (USEPA). The common methodology makes it possible to aggregate emissions estimates from different states and compare them to each other and to national emissions estimates.

---

[1] The term "greenhouse effect" describes the role of certain atmospheric gases that allow radiation from the sun to reach the Earth's surface but prevent, by absorption and reemission back to the surface, the Earth's surface radiation from loss to space. Scientists generally agree that the "greenhouse effect" is an important determinant of the balance between the Earth's incoming and outgoing radiation. Without the greenhouse effect, the Earth's surface would be too cold to sustain life. Controversy centers over the extent to which human activities are leading to an "enhanced" greenhouse effect by increasing greenhouse gas concentration, and the influence of this "enhanced" greenhouse effect on climate and natural systems.

Atmospheric science employs the term "radiative forcing" to refer to changes in the existing balance between the Earth's incoming and outgoing radiation. This balance can be upset by natural causes such as volcanic eruptions as well as by human activities such as greenhouse gas emissions. In addition to greenhouse gases, sources of radiative forcing include solar radiation, aerosols, and albedo. Albedo refers to the fraction of light or radiation that is reflected by the Earth. For example, polar ice and cloud cover increase the Earth's albedo.

Part 1 of this chapter summarizes and updates the baseline estimate of greenhouse gas emissions previously published in the *Inventory of Missouri's Estimated Greenhouse Gas Emissions in 1990,*[2] referred to throughout this study as the *1990 Inventory.* Part 2 summarizes methodological procedures and assumptions adopted or modified from the *1990 Inventory*. Parts 3 and 4 summarize Missouri greenhouse gas emissions trends through 1996 and projections through 2015.

The remaining chapters of the study amplify and support points made in Parts 1, 3 and 4 of this chapter. Because carbon dioxide (CO_2) emissions from fossil fuel combustion and especially from electric generation constitute the largest part of Missouri's GHG emissions, this source is treated separately in Chapters 2 through 4. Chapter 2 discusses trends through 1996, while Chapter 3 discusses projections for CO_2 emissions from the utility sector and Chapter 4 discusses emissions from the end-use sectors.

Chapter 5 deals with trends and projections for other sources of GHG emissions, including non-energy sources of CO_2, and sources of methane, nitrous oxide and perfluorinated carbons (PFCs). PFCs, which are minor but highly potent greenhouse gases produced as a byproduct of aluminum manufacture, are described in more detail in the *1990 Inventory*. Chapter 6 deals with CO_2 sequestration by Missouri forests.

[2] Missouri Department of Natural Resources, Division of Energy, Jefferson City, April 1996, Chapter 1.

Part 1: Baseline 1990 estimate of Missouri GHG emissions

Missouri's gross anthropogenic GHG emissions in 1990 totaled about 148 million tons. Energy use and other activities by Missourians emitted about 123 million tons of CO_2 and an additional 25 million tons of methane, nitrous oxide and PFCs.

Net anthropogenic GHG emissions in Missouri in 1990 amounted to about 121 million tons STCDE.[3] Estimated net emissions are lower than gross emissions because biomass growth in Missouri's forests, including below-ground root growth, offset about 27 million tons of GHG emissions in 1990.[4]

Section 1: GHG emissions from energy use

Table 1 provides detailed estimates of Missouri GHG emissions from energy use and other sources in 1990. For each source, Table 1 shows its percentage share of total GHG emissions. For example, fossil fuel combustion for energy use accounted for about 75 percent of total estimated GHG emissions.

For Missouri in 1990, coal combustion contributed about 49 percent of energy-related GHG emissions, petroleum about 39 percent and natural gas only about 12 percent. For the U.S. as a whole in 1990, coal accounted for only about 36 percent of energy-related GHG emissions, petroleum about 43 percent and natural gas about 20 percent. These differences between the share of coal, petroleum and natural gas at the national and state level reflect Missouri's reliance on coal to generate electricity and relatively low consumption of natural gas. Coal has the highest, and natural gas has the lowest, carbon content of any major fossil fuel.

In 1990, the utility sector accounted for about 46 percent of total CO_2 emissions from fossil fuel combustion. More than 99 percent of total utility CO_2 emissions were from combustion of coal.

Table 1 lists the utility sector separate from the four energy "end-use" sectors — transportation, commercial, industrial and residential sectors — because the utility sector consumes primary fossil fuel energy resources, such as coal, to generate electricity for these four "end-use" sectors.

In addition to electricity, the four end-use sectors listed in Table 1 use both primary fossil fuel energy resources, such as natural gas and petroleum, and electricity, which is a secondary form of energy. Examples of primary fossil fuel consumption in the end-use sectors are the use of motor gasoline and diesel fuel for highway travel in the transportation sector and the use of natural gas for heating and cooking in the residential and commercial sectors.

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[3] Emissions of methane, nitrous oxide and PFCs are reported in Short Tons Carbon Dioxide Equivalent (STCDE). The derivation of this unit of common measure is based on Global Warming Potential (GWP) factors for the different gases, as explained later in this section.

[4] In order to grow, trees and other perennial plants remove and store (sequester) carbon dioxide (CO_2). Following the methodology of the *1990 Inventory*, this removal is considered to be a result of forest management practices and therefore to offset an equivalent quantity of GHG emissions.

Table 1 - Missouri GHG sources in 1990, showing each source's estimated share of total gross GHG emissions

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

Carbon dioxide emissions	123,129	83.2%
CO_2 from fossil fuel combustion	111,472	75.3%
Energy end-use sectors	59,934	40.5%
Transportation	36,782	24.8%
Gasoline	25,826	17.4%
Diesel	7,578	5.1%
Jet fuel	2,971	2.0%
Other	408	0.3%
Commercial	4,625	3.1%
Natural gas	3,494	2.4%
Petroleum	721	0.5%
Coal	410	0.3%
Industrial	10,284	6.9%
Natural gas	3,077	2.1%
Petroleum	4,107	2.8%
Coal	3,100	2.1%
Residential	8,242	5.6%
Natural gas	6,822	4.6%
Petroleum	1,200	0.8%
Coal	221	0.1%
Electric utility sector	51,539	34.8%
Natural gas	207	0.1%
Petroleum	93	0.1%
Coal	51,238	34.6%
Other sources of CO_2	11,656	7.9%
Oxidation of carbon monoxide	1,460	1.0%
Non-energy uses of fossil fuels	1,345	0.9%
Limestone use	4,445	3.0%
Land use changes	4,407	3.0%
Methane emissions	16,527	11.2%
Agriculture	10,463	7.1%
Municipal waste	5,419	3.7%
Fossil fuel prod'n & distribution	501	0.3%
Highway travel	143	0.1%
Nitrous oxide emissions	3,805	2.6%
Agriculture	2,333	1.6%
Highway travel	1,080	0.7%
Nitric acid production	391	0.3%
PFCs from aluminum production	4,611	3.1%
Total greenhouse gas sources	***148,071***	***100.0%***

Table 2 reports the same CO_2 emissions from fossil fuel combustion that are reported in Table 1, however, Table 2 drops utilities as a separate sector and allocates utility CO_2 emissions to the end-use sectors in proportion to their consumption of electricity. Estimated Tons of emissions per capita are shown for all sources, and estimated tons per $1 million Gross State Product (GSP) are shown for those sources whose level of emissions is closely related to the production and transportation of goods and services. The table also shows each source's percentage of total CO_2 emissions from fossil fuel combustion.

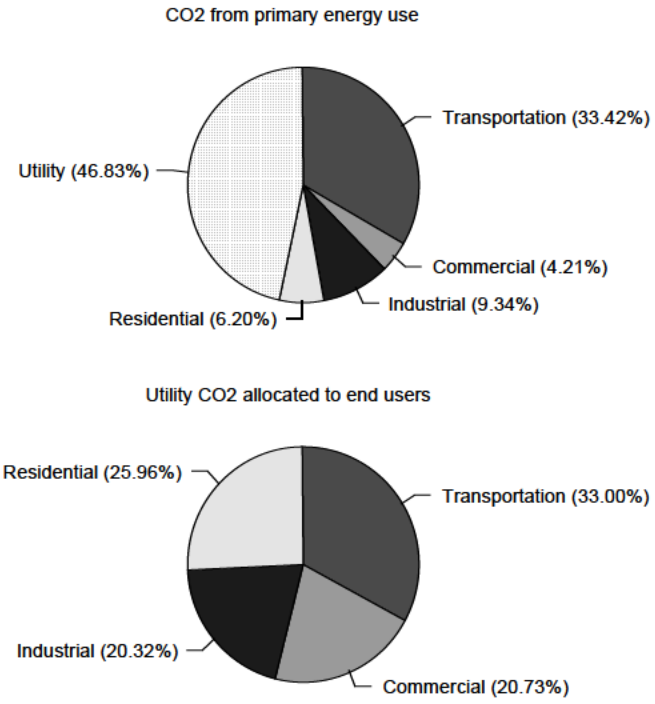
Table 2 - Estimated Missouri CO_2 emissions from fossil fuel combustion in 1990

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	CO_2 emissions (1,000 Tons)	**Tons per person**	**Tons per $1 million GSP**	**Percent of total emissions**
Energy end-use sectors	111,472	21.8		100.0%
Transportation	36,782	7.2		33.0%
Gasoline	25,826	5.0		23.9%
Diesel	7,578	1.5	82.2	6.9%
Jet fuel	2,971	0.6	32.2	2.8%
Other	408	0.1		0.4%
Electricity	0	0.0		0.0%
Commercial	23,104	4.5		20.7%
Electricity	18,479	3.6		16.6%
Natural gas	3,494	0.7		3.1%
Petroleum	721	0.1		0.6%
Coal	410	0.1		0.4%
Industrial	22,649	4.4	245.7	20.3%
Electricity	12,365	2.4	134.2	11.1%
Natural gas	3,077	0.6	33.4	2.7%
Petroleum	4,107	0.8	44.6	3.7%
Coal	3,100	0.6	33.6	2.8%
Residential	28,937	5.7		26.0%
Electricity	20,694	4.0		18.6%
Natural gas	6,822	1.3		6.1%
Petroleum	1,200	0.2		1.1%
Coal	221	0.0		0.2%
Electricity	51,539	10.1		46.2%
Commercial	18,479	3.6		16.6%
Industrial	12,365	2.4		11.1%
Residential	20,694	4.0		18.6%

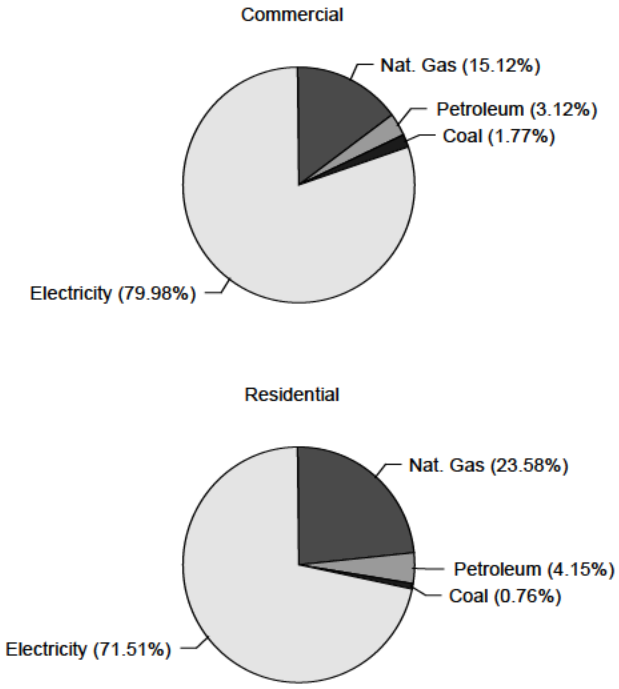
Since the transportation sector used virtually no electricity in 1990, Table 2 shows a much more even distribution of CO_2 emissions across the four end-use sectors than in Table 1. In 1990, transportation accounted for about 37 million tons of emissions from primary fossil fuel use. This amounts to more than 60 percent of total emissions from primary fossil fuel use as reported in Table 1. However, Table 2 indicates that transportation accounts for only about 33 percent of total CO_2 emissions from the end-use sectors after allocating emissions from electricity use to the sectors. The residential sector accounts for about 26 percent, and the commercial and industrial sectors each account for about 20-21 percent.

Chart 1 - Five-sector distribution of CO_2 emissions from primary energy use versus four-sector distribution based on allocating utility CO_2 emissions to end users of electricity, 1990



In 1990, about 76 percent of 1990 CO_2 emissions from electric generation were due to use in the residential and commercial sectors. In these two sectors, electricity is the dominant source of energy, with natural gas a distant second. Electricity use accounted for about 72 percent of residential and 80 percent of commercial CO_2 emissions in 1990. On a per-capita basis, the residential sector emitted about 4.0 tons of CO_2 from electricity use, and the commercial sector about 3.6 tons of CO_2, for each Missourian in 1990.

Chart 2 - CO_2 emissions by energy source in the commercial and residential sectors, 1990



Missouri's industrial sector is less energy-intensive than the national average, and electricity is one of a wide variety of energy resources used in the sector. Nevertheless, electricity use accounted for more than half of industrial CO_2 emissions in 1990. In 1990, the industrial sector emitted about 134 tons of CO_2 from electricity use per $1 million Gross State Product (GSP).

Section 2: GHG emissions from sources other than energy use

About 25 percent of estimated Missouri GHG emissions in 1990 were from sources other than energy use. Land use changes, industrial and agricultural uses of limestone, industrial and transportation use of fossil fuels for purposes other than energy, and oxidation of carbon monoxide emitted by highway vehicles and stationary industrial sources accounted for about 11.7 million tons of CO_2 emissions, about 8 percent of total CO_2 emissions in 1990.

Methane, nitrous oxide and PFC emissions accounted for about 25 million tons of GHG emissions, measured in units of Short Tons Carbon Dioxide Equivalent (STCDE). The leading sources of non-CO_2 emissions were agriculture, industry and municipal waste management, as follows:

1. Agriculture was the leading source of methane and nitrous oxide emissions in the state. In 1990, beef cattle, dairy cattle and swine operations generated more than 10 million tons (STCDE) of methane emissions, and use of nitrogenous fertilizers generated more than 2 million tons (STCDE) of nitrous oxide emissions.

2. Industrial production of aluminum accounted for about 4.6 million tons (STCDE) of PFCs and nitric acid production accounted for an additional 0.4 million tons (STCDE) of nitrous oxide. This amount was in addition to a variety of non-energy-related industrial sources of CO_2, including non-energy uses of fossil fuels, production of lime and cement from limestone.

3. Finally, municipal waste management was an important source of methane emissions. Anaerobic decomposition of organic waste deposited in municipal landfills generated more than 5 million tons (STCDE) of methane emissions in 1990.

Short Tons Carbon Dioxide Equivalent (STCDE) is the unit of common measure used throughout this study. Global Warming Potential (GWP) factors developed by the Intergovernmental Panel on Climate Change (IPCC) are the basis for this unit of measure. For example, Table 1 estimates that 16.4 million tons (STCDE) of methane were emitted in Missouri in 1990. This means it would have required 16.4 million short tons of CO_2 to equal the global warming potential (GWP) of the methane that was emitted. Because estimates given using STCDE units weight the emissions estimate for each gas by its GWP factor, it is possible to add or compare the emissions estimates for different greenhouse gases.

Part 2: Methodological assumptions from the *1990 Inventory*

Estimates of GHG emissions in this report closely follow the methodological procedures described in the *1990 Inventory,* which were based, with some refinements, on methodology specified by the U.S. Environmental Protection Agency (USEPA) in its *State Workbook*.[5] For additional discussion of the procedures, the reader is referred to the *1990 Inventory*.

The estimates are limited to the anthropogenic (from human sources) emissions of four greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and perfluorinated carbons (PFCs). Stratospheric and troposphere ozone, carbon monoxide (CO), nitrogen oxides (NO_x), non-methane volatile organic compounds (NMVOCs), chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs) and other ozone-depleting compounds (ODCs) are omitted as explained in the *1990 Inventory*, Section 1.1.

Estimates of CO_2 emissions from the combustion of fossil fuels are probably the most reliable estimates contained in the *1990 Inventory* and this report. The estimation of CO_2 emissions from fossil fuel combustion requires estimating the physical quantity (tons, barrels, cubic feet, etc.) of the fuel burned, its heat content (Btus)[6] and its carbon content. For fossil fuel usage and quality data, the *1990 Inventory* and this report rely primarily on federal data sources compiled from reports by Missouri state agencies (such as the Missouri Department of Revenue or Missouri Department of Transportation) or producers and consumers of fossil fuels (such as refiners and electric utilities). Most heat and carbon coefficients came from the U.S. Department of Energy's Information Administration (EIA) or from USEPA. Because of the prominence of coal combustion by electric utilities as a source of CO_2 emissions in Missouri, individual heat content coefficients and carbon coefficients were estimated for each coal-fired utility plant in the state using data provided by EIA.

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[5] USEPA, State and Local Outreach Program, *State Workbook: Methodologies for Estimating Greenhouse Gas Emissions*, Washington, DC, 1995.

[6] Although the fuel supply industry regularly reports fuel consumption in physical units (such as tons of coal, cubic feet of natural gas or barrels of oil), the methodology to estimate emissions is based on measuring consumption by a common unit of heat content, the British Thermal Unit (Btu). The factors used to convert physical to thermal units, are listed on page 161 in the *1990 Inventory*.

The use of a standard coefficient to estimate heat content of fossil fuels consumed is one source of error in estimating emissions. The heat content of coal, natural gas and petroleum is variable. For example, the energy content of utilities' coal receipts varies widely, even for the same grade of coal from the same state of origin (EIA, *Cost and Quality of Fuels for Electric Utility Plants*, annual report). The thermal content reported by the utilities is itself based on sampling and therefore subject to error.

Table 1 in the previous section indicates that methane, nitrous oxide and PFCs accounted for about 17 percent of total estimated Missouri GHG emissions in 1990. In contrast, the *1990 Inventory* reported that these gases accounted for about 14 percent. The primary reason for the increase in the share of the three gases is that this report uses higher Global Warming Potential (GWP) factors[7] for methane, nitrous oxide and perfluorinated carbon emissions.

Table 3 lists the Intergovernmental Panel on Climate Change's (IPCC) 1992 and 1995 GWP factors for methane (CH_4), nitrous oxide (N_2O) and perfluorinated carbons (PFCs). This report uses the 1995 GWP factors, which are higher than the 1992 GWP factors used in the *1990 Inventory*. Use of the 1995 factors increases estimated methane emissions by about 11 percent and nitrous oxide emissions by about 19 percent.

Table 3 - IPCC 1992 and 1995 GWP factors

	IPCC 1992 GWP factors	IPCC 1995 GWP factors
Carbon dioxide (CO_2)	1	1
Methane (CH_4)	22	24.5
Nitrous oxide (N_2O)	270	320
Perfluorinated carbons (PFCs)	5,400	6,300 (CF_4)* 12,500 (C_2F_6)*

See Chapter 5, Part 4.

In addition to using higher GWP factors, this report makes other minor departures from the methodology used in the *1990 Inventory*. In estimating PFC emissions from aluminum, the *1990 Inventory* averaged two sources, Noranda Aluminum's estimates of PFC emissions and independent estimates based on *State Workbook* methodology. This study drops the averaging procedure and reports only Noranda Aluminum's estimates.

In addition to these methodological revisions, this report has corrected data for several sources of CO_2 and methane emissions. Otherwise, this report uses the same methodology and data used in the *1990 Inventory* for methane (CH_4), nitrous oxide (N_2O) and perfluorinated carbons (PFCs). Table 4 indicates the resulting revisions in emissions estimates for methane (CH_4), nitrous oxide (N_2O) and perfluorinated carbons (PFCs).

[7] The concept of global warming potential, as developed by the Intergovernmental Panel on Climate Change (IPCC), is based on a comparison of the radiative forcing effect of the concurrent emission into the atmosphere of an equal quantity of CO_2 and another greenhouse gas. Each gas has a different instantaneous radiative forcing effect. In addition, the atmospheric concentration attributable to a specific quantity of each gas declines with time; IPCC assumes a 100-year time horizon. For additional discussion, see the *1990 Inventory*, Section 1.2.

Table 4 - Changes in estimates of Missouri's 1990 methane, nitrous oxide and PFC emissions

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	Original estimate (STCDE) weighted by 1992 factors	**Revised estimate (STCDE) weighted by 1995 factors**	**Change in estimate (STCDE)**
Methane emissions	14,755	16,527	1,772
Agriculture	9,005	10,463	1,459
Beef cattle	5,098	5,677	579
Dairy cattle	1,624	1,808	185
Swine	2,076	2,747	671
Other livestock	153	170	17
Rice cultivation	55	61	6
Burning crop wastes	0	0	0
Municipal Waste	5,171	5,419	588
Fossil fuel production & distribution	450	501	51
Transportation	129	143	15
Nitrous oxide emissions	3,210	3,805	595
Agriculture	1,969	2,333	365
Transportation	911	1,080	169
Nitric acid production	330	391	61
PFCs from aluminum production	3,625	4,611	982
CF_4 emissions	3,299	3,847	548
C_2F_6 emissions	329	763	434
Total non-CO_2 GHG emissions	***21,590***	***24,942***	***3,348***

Following the example of the 1990 Inventory, this report assumes zero net emissions from use of nuclear fuel and biofuels. Moreover, the report excludes accounting for out-of-state emissions. Because Missouri in 1990 imported nearly all its fossil fuels, nuclear fuel and ethanol, emissions associated with the production and transportation of these fuels occurred primarily out-of-state and therefore are not included in trend estimates for the state's GHG emissions.

Although there is some uncertainty associated with all estimates, the level of uncertainty is greater for some GHG emissions sources than others. In an authoritative discussion, the U.S. Department of Energy's Energy Information Administration (EIA) concludes that estimates of CO_2 emissions from the combustion of fossil fuels are probably reliable within five percent.[8] Because these emissions can be estimated with the greatest reliability and make up the greatest portion (86 percent) of Missouri's GHG emissions, and because there are many possible state actions that could influence the level of these emissions, trends and projections in CO_2 emissions receive the greatest attention in this report.

Estimates of methane emissions are generally more uncertain than for CO_2. Although methane emissions in Missouri are less important than CO_2 emissions, they do constitute about ten percent of total GHG emissions, and there are significant "no regret" actions that may influence the level of methane emissions. Therefore, trends and projections in methane emissions also receive attention in this report.

Estimates of nitrous oxide emissions are highly uncertain. Because nitrous oxide emissions make up the smallest slice of the GHG emissions "pie" and because they are relatively impervious to possible state actions, trends and projections in nitrous oxide emissions receive the least attention in this report.

[8] EIA, *Emissions of Greenhouse Gases in the United States, 1987-1994*, 1985, p. 81. EIA discusses uncertainties in the volume of fuel consumed, characteristics of fuel consumed, emissions coefficients and coverage. For the most part, the estimates in the *1990 Inventory* and this report depend on coefficients estimated by EIA or data reported to EIA by producers and consumers of fossil fuels.

Part 3: Trends in Missouri GHG emissions since 1990

Missouri's gross GHG emissions increased from about 148 million tons in 1990 to 168 million tons in 1996, growing 13 percent at a 2.1 percent annual average growth rate. Gross 1996 emissions included about 145 million tons of CO_2 and 23 million tons of other gases.

Table 5, which is similar in format to Table 1, provides detailed comparisons of Missouri GHG emissions sources in 1990 and 1996. CO_2 emissions from fossil fuel combustion for energy use increased by about 22 million tons, growing about 20 percent at a 3 percent average annual growth rate.[9] Energy-related CO_2 emissions accounted for nearly 80 percent of total estimated GHG emissions in 1996 compared to about 75 percent in 1990.

Table 6 and Table 7 summarize GHG emissions for each year between 1990 and 1996 and indicate percentage increases or decreases in the different emissions categories.

The pattern of increase between 1990 and 1996 was not linear. Net GHG emissions actually dropped by about 3.4 million tons (STCDE) through 1993, but then increased by nearly 24 million tons (STCDE) from 1993 through 1996.

Factors influencing changes in GHG emissions between 1990 and 1996 included:

- 1990-91: Reductions in perfluorinated carbon (PFC) emissions led the 1990 and 1991 decline in net GHG emissions. Reduction in PFCs are produced from aluminum manufacture. Noranda Aluminum has dramatically reduced PFC emissions at its Missouri plant through ongoing efforts to improve the efficiency of its manufacturing processes.

- 1992-93: Decreasing CO_2 emissions from coal-fired utility boilers led the 1992 and 1993 decline.

- 1994-96: Increasing CO_2 emissions from coal-fired utility boilers led the increase in net GHG emissions between 1993 and 1996.

- Other significant sources of the increase in net emissions between 1990 and 1996 were increases in energy-based CO_2 emissions from the transportation, residential and commercial sectors and increases in methane emissions from swine, beef cattle and municipal landfills.

[9] Nationally, USEPA estimates that energy-related CO_2 emissions grew a little more than 9 percent during this period. USEPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1996*, 1998, p. 2-3.

Table 5 - Missouri GHG sources in 1990 and 1996, showing each source's estimated share of total gross GHG emissions and average annual rate of growth

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	Estimated 1990 Gross Emissions		Estimated 1996 Gross Emissions		Rate 1990-96
Carbon dioxide emissions	123,129	83.1%	145,282	86.5%	2.8%
CO_2 from fossil fuel combustion	111,472	75.2%	133,410	79.4%	3.0%
Energy end-use sectors	59,934	40.4%	70,122	41.7%	2.7%
Transportation	36,782	24.8%	44,207	26.3%	3.1%
Gasoline	25,826	17.4%	28,044	16.7%	1.4%
Diesel	7,578	5.1%	10,131	6.0%	5.0%
Jet fuel	2,971	2.0%	5,672	3.4%	11.4%
Other	408	0.3%	359	0.2%	-2.1%
Commercial	4,625	3.1%	5,465	3.3%	2.8%
Natural gas	3,494	2.4%	4,258	2.5%	3.4%
Petroleum	721	0.5%	881	0.5%	3.4%
Coal	410	0.3%	325	0.2%	-3.8%
Industrial	10,284	6.9%	10,612	6.3%	0.5%
Natural gas	3,077	2.1%	3,921	2.3%	4.1%
Petroleum	4,107	2.8%	4,127	2.5%	0.1%
Coal	3,100	2.1%	2,564	1.5%	-3.1%
Residential	8,242	5.6%	9,838	5.9%	3.0%
Natural gas	6,822	4.6%	7,986	4.8%	2.7%
Petroleum	1,200	0.8%	1,680	1.0%	5.8%
Coal	221	0.1%	173	0.1%	-4.0%
Electric utility sector	51,539	34.8%	63,288	37.7%	3.5%
Natural gas	207	0.1%	284	0.2%	5.4%
Petroleum	93	0.1%	117	0.1%	3.8%
Coal	51,238	34.6%	62,887	37.4%	3.5%
Other sources of CO_2	11,656	7.9%	11,872	7.1%	0.3%
Oxidation of carbon monoxide	1,460	1.0%	1,650	1.0%	2.1%
Non-energy uses of fossil fuels	1,345	0.9%	982	0.6%	-5.1%
Limestone use	4,445	3.0%	4,834	2.9%	1.4%
Land use changes	4,407	3.0%	4,407	2.6%	0.0%
Methane emissions	16,712	11.3%	18,290	10.9%	1.5%
Agriculture	10,463	7.1%	11,166	6.6%	1.1%
Municipal waste	5,604	3.8%	6,481	3.9%	2.5%
Fossil fuel prod'n & distribution	501	0.3%	501	0.3%	0.0%
Highway travel	143	0.1%	143	0.1%	0.0%
Nitrous oxide emissions	3,805	2.6%	3,820	2.3%	0.1%
Agriculture	2,333	1.6%	2,348	1.4%	0.1%
Highway travel	1,080	0.7%	1,080	0.6%	0.0%
Nitric acid prodcution	391	0.3%	391	0.2%	0.0%
PFCs from aluminum production	4,611	3.1%	641	0.4%	-28.0%
Total greenhouse gas sources	***148,256***	***100.0%***	***168,033***	***100.0%***	***2.1%***

Table 6 - Summary of Missouri GHG emissions sources, 1990-96

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1991	1992	1993	1994	1995	1996
Greenhouse gas sources	148,256	144,688	144,397	144,229	154,381	161,561	168,033
Carbon dioxide emissions	123,129	122,635	122,326	121,502	131,112	138,482	145,282
Energy	111,472	111,638	110,977	110,519	119,608	127,156	133,410
Energy end-use sectors	59,934	59,781	60,631	64,767	65,764	66,913	70,122
Electric utility sector	51,539	51,857	50,346	45,752	53,843	60,243	63,288
Other	11,656	10,998	11,349	10,983	11,504	11,326	11,872
Methane emissions	16,712	16,762	17,056	17,569	18,343	18,159	18,290
Nitrous oxide emissions	3,805	3,859	3,925	4,001	3,877	3,855	3,820
PFCs - aluminum production	4,611	1,431	1,090	1,157	1,049	1,065	641

Table 7 - Summary of percentage increases in Missouri GHG emissions in 1991-96 compared to 1990

	1991	1992	1993	1994	1995	1996
Greenhouse gas sources	-2.4%	-2.6%	-2.7%	4.1%	9.0%	13.3%
Carbon dioxide emissions	-0.4%	-0.7%	-1.3%	6.5%	12.5%	18.0%
Energy	0.1%	-0.4%	-0.9%	7.3%	14.1%	19.7%
Energy end-use sectors	-0.3%	1.2%	8.1%	9.7%	11.6%	17.0%
Electric utility sector	0.6%	-2.3%	-11.2%	4.5%	16.9%	22.8%
Other	-5.7%	-2.6%	-5.8%	-1.3%	-2.8%	1.9%
Methane emissions	0.3%	2.1%	5.1%	9.8%	8.7%	9.4%
Nitrous oxide emissions	1.4%	3.2%	5.2%	1.9%	1.3%	0.4%
PFCs - aluminum production	-69.0%	-76.4%	-74.9%	-77.3%	-76.9%	-86.1%

The relative share of CO_2 emissions in the total mix of GHG emissions in Missouri increased between 1990 and 1996. In 1990, CO_2 held an estimated 83 percent share of gross GHG emissions in Missouri.[10] By 1996, this share increased to about 86 percent.

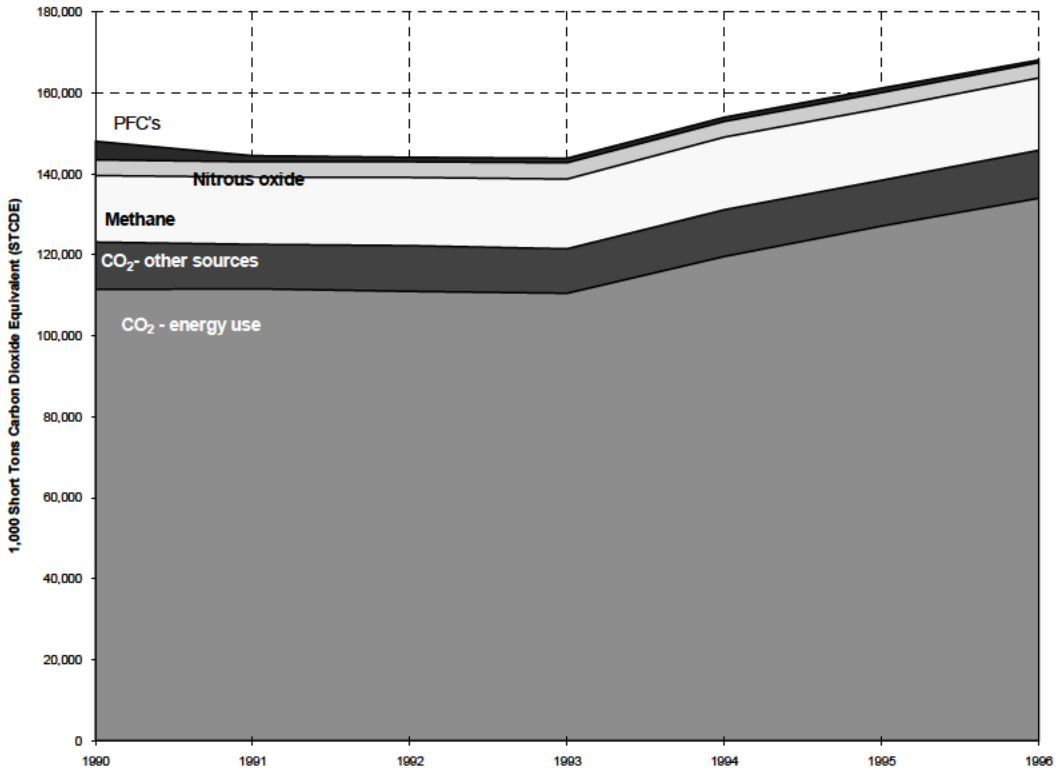
Estimated methane emissions also increased during the period, but not as rapidly as CO_2 emissions. The share of methane emissions in the total mix remained at about 11 percent.

Estimated nitrous oxide emissions remained about constant from 1990 through 1996 and dropped from about 2.6 percent to 2.3 percent of the total mix. The largest reduction was in PFC emissions, which dropped from about 3.1 percent of total emissions in 1990 to less than 1 percent in 1996.

The following chart illustrates the relative shares of CO_2, methane, nitrous oxide and perfluorinated carbons in Missouri gross GHG emissions between 1990 and 1996. Net emissions are lower than gross emissions because they take into account sequestration from forest growth.

[10] As explained in Part 1 of this chapter, this is lower than the 85.5 percent share estimated by the *1990 Inventory* because that study used Global Warming Potential (GWP) factors estimated by IPCC in 1992, whereas this study uses the GWP factors estimated in IPCC in 1995. The 1995 GWP factors ascribe a higher relative Global Warming Potential to methane, nitrous oxide and perfluorinated carbons than the 1992 factors.

Chart 3 - Missouri GHG emissions trends, by gas type, 1990-96



"Net" GHG emissions take into account the impact of carbon sequestration that occurs when there is an increase in the biomass in Missouri forests. Net anthropogenic GHG emissions increased from about 121 million tons (STCDE) in 1990 to about 142 million tons (STCDE) in 1996, growing 17 percent at a 2.7 percent annual average growth rate. The increase in net emissions was due to an increase in gross emissions and a decrease in estimated sequestration by Missouri's forests. Sequestration decreased an estimated 5 percent between 1990 and 1996.

Section 1: Trends in Missouri CO_2 emissions from fossil fuel combustion, 1990-96

CO_2 emissions from fossil fuel combustion increased by about 20 percent, between 1990 and 1996. The leading source of the increase was an expansion in electric utility coal use. Emissions from utility use of coal account for more than 99 percent of utility CO_2 emissions. Utility emissions increased about 23 percent between 1990 and 1996. Net emissions from the other four energy sectors (transportation, commercial, industrial and residential) increased by about 17 percent.

CO_2 emissions from utility coal use led both the 1991 through 1993 decline in Missouri's net GHG emissions and the 1994 through 1996 increase in net GHG emissions. Utility CO_2 emissions from coal decreased by nearly 6 million tons between 1990 and 1993. About 1 million tons of this decrease occurred between 1991 and 1992, and the remaining 5 million occurred in 1993. The decline probably occurred for different reasons in each of the three years: in 1991, because municipal utilities and co-op utilities took advantage of low prices for natural gas and wholesale power to substitute for coal; in 1992, because residential and commercial electricity sales were affected by an unusually cool summer; and in 1993, because flooding and a labor strike cut off Eastern coal supplies and also because natural gas was inexpensive and hydroelectric power was abundant.

From 1994 through 1996, following this 3-year decline in CO_2 emissions from utility coal use, generation from coal steadily increased. Utility coal use in 1996 was 20 percent higher than in 1990 and 37 percent higher than in 1993. The increase came as utilities, responding to growing electricity demand and the decreasing price of coal, took advantage of the existing excess coal generating capacity in Missouri.

Electricity sales in 1996 were about 20 percent higher than in 1990; compared to the previous year, electricity sales increased by about 1.8 percent in 1994, 4.3 percent in 1995 and 4.2 percent in 1996.[11] Residential and commercial electricity sales during this period increased in response to population and economic growth in the state. Industrial electricity sales increased due to these factors as well as steadily decreasing electricity rates for industry.[12]

On the supply side, the average delivered cost of coal to Missouri utilities decreased rapidly after 1992 as Missouri utilities switched to coal imported from Wyoming and other western states. Missouri utilities' average delivered price of coal in 1996 was nearly 30 percent lower than in 1992.

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[11] Due to variations in the weather, the growth of electricity sales in Missouri slowed to only about 0.5 percent in 1997 but increased to about 7.8 percent during the first half of 1998.

[12] During the 20 years prior to 1990, the average price for electricity delivered to Missouri industry increased every year except 1984. Since 1990, the average price to industry has decreased every year. The average price in nominal dollars for electricity delivered to Missouri industry decreased about 8.3 percent between 1990 and 1995, from $14.50 per million Btu in 1990 to $13.29 in 1995. The average price to residential and commercial customers also decreased between 1990 and 1995, but the decrease was smaller (4.1 percent to commercial customers and 1.4 percent to residential customers) and price changes followed a mixed pattern of price increases and decreases from year to year. USDOE/EIA, *State Energy Price and Expenditure Report*, 1995.

The steady increase in utility generation from coal between 1993 and 1996 led to a rapid increase in CO_2 emissions. CO_2 emissions from utility coal use increased by more than 18 million tons between 1994 and 1996. The level of utility CO_2 emissions from coal in 1996, 62.9 million tons, was about 23 percent higher than in 1990 and 39 percent higher than in 1993.

Electric utilities increased their share of energy-related CO_2 emissions from about 46 percent in 1990 to about 47 percent in 1996. With continued growth in transportation emissions during 1990 through 1996, the share of the transportation sector also increased slightly. The residential and commercial sectors' shares remained about constant, and the industrial sector's share decreased from about 10 percent to about 8 percent.

Table 8 and Table 9 summarize sectoral trends between 1990 and 1996 in CO_2 emissions from fossil fuel combustion.

Table 8 - Trends in CO_2 emissions from fossil fuel combustion, by primary energy use sector, 1990-96

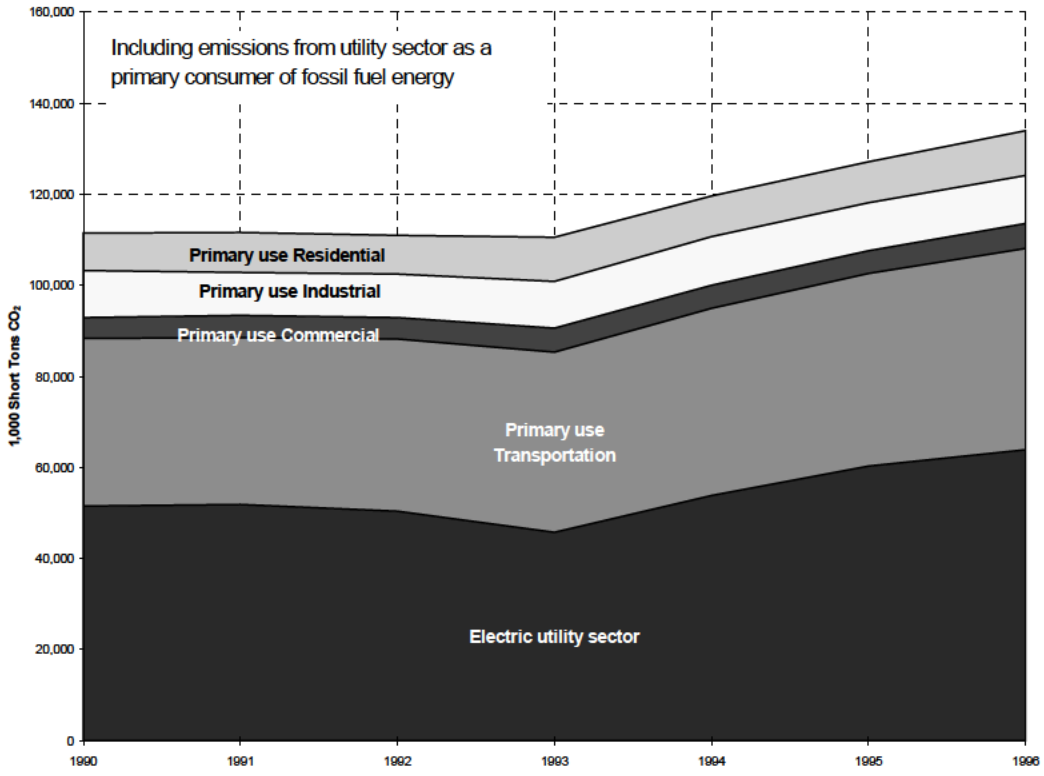
Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996
Primary use							
Transportation	36,782	36,636	37,813	39,542	41,110	42,351	44,207
Commercial	4,625	4,898	4,730	5,300	5,071	4,991	5,465
Industrial	10,284	9,414	9,574	10,241	10,634	10,497	10,612
Residential	8,242	8,833	8,515	9,684	8,950	9,073	9,838
Electric utility sector	51,539	51,857	50,346	45,752	53,843	60,243	63,288
Total	***111,472***	***111,638***	***110,977***	***110,519***	***119,608***	***127,156***	***133,410***

Table 9 - Percentage increases in CO_2 emissions from fossil fuel combustion in 1991-96 compared to 1990

	1991	1992	1993	1994	1995	1996
Primary use						
Transportation	-0.4%	2.8%	7.5%	11.8%	15.1%	20.2%
Commercial	5.9%	2.3%	14.6%	9.6%	7.9%	18.2%
Industrial	-8.5%	-6.9%	-0.4%	3.4%	2.1%	3.2%
Residential	7.2%	3.3%	17.5%	8.6%	10.1%	19.4%
Electric utility sector	0.6%	-2.3%	-11.2%	4.5%	16.9%	22.8%
Total	***0.1%***	***-0.4%***	***-0.9%***	***7.3%***	***14.1%***	***19.7%***

Chart 4 - Trends in CO_2 emissions from fossil fuel combustion, 1990-96



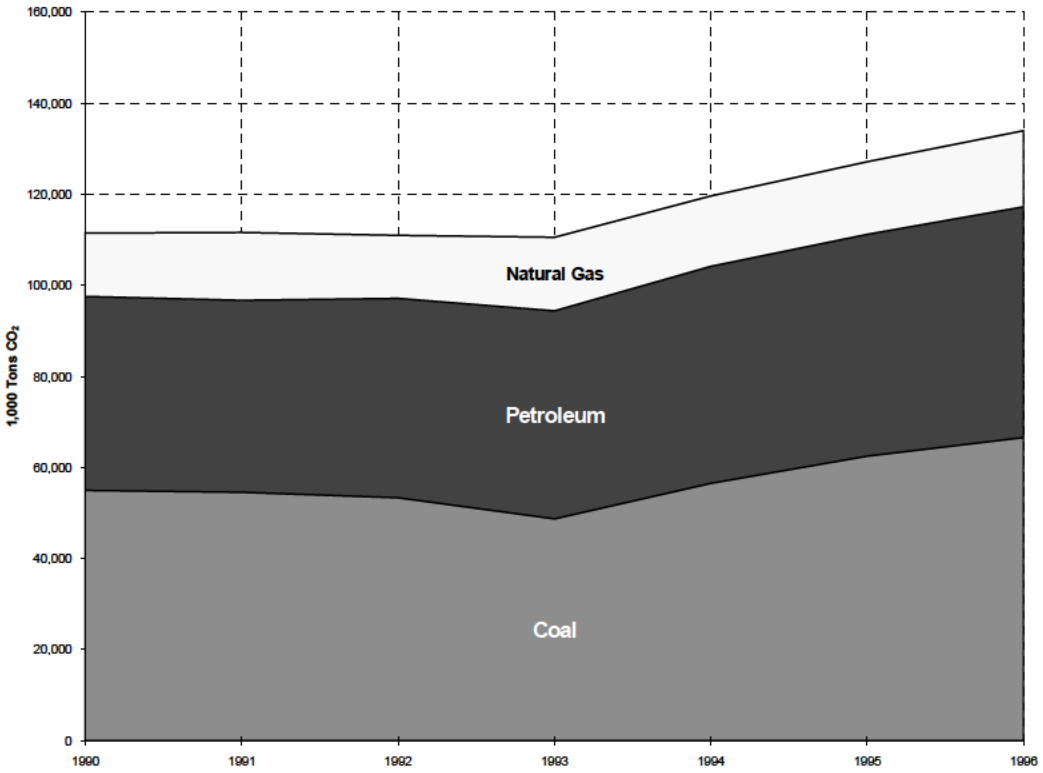
In addition to CO_2 emissions from coal-fired utility boilers, other sources of the large increase of energy-related CO_2 emissions between 1990 and 1996 included:

CO_2 emissions from increased use of gasoline, diesel and jet fuel in the transportation sector, which increased by about 5 million tons (STCDE); and

CO_2 emissions from increased use of natural gas in the commercial, industrial and residential sectors, which increased by about 3 million tons (STCDE).

Thus, as a result of increased coal consumption in the utility sector, petroleum consumption in the transportation sector and natural gas consumption in the other sectors, estimated energy-related CO_2 emissions from all three fuel types increased during 1990 through 1996.

Chart 5 - Trends in CO_2 emissions from fossil fuel combustion, by fuel type, 1990-96



Tables 10 and 11 indicate the emissions increases in the three fuel types.

Table 10 - Trends in CO_2 emissions for coal, petroleum and natural gas, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996
Coal	54,969	54,490	53,357	48,717	56,479	62,464	65,949
Petroleum	42,591	42,237	43,721	45,614	47,634	48,739	50,733
Natural Gas	13,912	14,911	13,899	16,188	15,494	15,953	16,729
Total	***111,472***	***111,638***	***110,977***	***110,519***	***119,608***	***127,156***	***133,411***

Table 11 - Percentage increases in CO_2 emissions from coal, petroleum and natural gas in 1991-96 compared to 1990

	1991	1992	1993	1994	1995	1996
Coal	-0.9%	-2.9%	-11.4%	2.7%	13.6%	20.0%
Petroleum	-0.8%	2.7%	7.1%	11.8%	14.4%	19.1%
Natural Gas	7.2%	-0.1%	16.4%	11.4%	14.7%	20.2%
Total	***0.1%***	***-0.4%***	***-0.9%***	***7.3%***	***14.1%***	***19.7%***

As discussed in Chapter 2, Part 3, emissions from fossil fuel-based electricity generation may be allocated to the other four sectors according to the sectors' share of electricity use. In 1996, as in 1990, transportation was the leading sectoral source of emissions among the four end-use sectors. Between 1990 and 1996, the estimated shares of the transportation and industrial sectors dropped slightly, and those of the residential and commercial sectors rose slightly, but the shifts were all less than one percent. Tables 12 and 13 summarize the resulting trends by sector:

Table 12 - Trends in CO_2 emissions, by end-use sector, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996
Transportation	36,782	36,636	37,813	39,542	41,118	42,354	44,210
Commercial	23,104	23,262	22,937	21,551	24,486	26,768	28,450
Industrial	22,649	21,447	22,010	20,869	23,359	24,362	24,985
Residential	28,937	30,292	28,218	28,557	30,653	33,674	35,768
Total end-use sectors	***111,472***	***111,638***	***110,977***	***110,519***	***119,616***	***127,159***	***133,413***

Table 13 - Percentage increases in CO_2 emissions from Missouri end-use sectors in 1991-96 compared to 1990

	1991	1992	1993	1994	1995	1996
Transportation	-0.4%	2.8%	7.5%	11.8%	15.1%	20.2%
Commercial	0.7%	-0.7%	-6.7%	6.0%	15.9%	23.1%
Industrial	-5.3%	-2.8%	-7.9%	3.1%	7.6%	10.3%
Residential	4.7%	-2.5%	-1.3%	5.9%	16.4%	23.6%
Total end-use sectors	***0.1%***	***-0.4%***	***-0.9%***	***7.3%***	***14.1%***	***19.7%***

Section 2: Missouri GHG emissions from sources other than energy use, 1990-96

This section reviews changes in CO_2 emissions from non-energy sources, changes in CO_2 sequestration due to forest growth and changes in emissions of gases other than CO_2.

CO_2 from sources other than energy

Between 1990 and 1996, while energy-based CO_2 emissions increased at a 3.1 percent average annual growth rate, total non-energy-based CO_2 emissions increased only about 0.2 million tons (STCDE) over their level in 1990, an average annual growth rate of about 0.3 percent. Between 1990 and 1996, non-energy-based CO_2 emissions for several sources fell below their 1990 level.[13] The share of non-energy emissions as a percentage of total CO_2 emissions decreased from 9.5 percent in 1990 to about 8.2 percent in 1996. Table 14 summarizes estimates for sources of non-energy-related CO_2 emissions during 1990-96, and Table 15 summarizes percentage changes for these sources.

Table 14 - Trends in Missouri CO_2 emissions from sources other than fossil fuel combustion, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996
Oxidation of carbon monoxide	1,460	1,433	1,481	1,516	1,570	1,595	1,650
Transportation	1,293	1,279	1,325	1,349	1,396	1,424	1,477
Industrial	168	153	156	167	173	171	173
Non-energy uses of fossil fuels	1,345	849	951	910	960	946	982
Industrial sector uses	1,111	640	737	693	733	720	754
Transportation sector - lubricants	234	210	214	218	227	226	228
Limestone use	4,445	4,309	4,510	4,150	4,568	4,379	4,834
Cement Production	2,260	2,156	2,382	2,255	2,629	2,424	2,562
Lime Manufacture	1,599	1,597	1,579	1,374	1,413	1,413	1,731
Decomposition of agricultural lime	586	555	549	522	526	541	541
Land use changes	4,407	4,407	4,407	4,407	4,407	4,407	4,407
Net loss of above-ground "sinks"	1,613	1,613	1,613	1,613	1,613	1,613	1,613
Soil carbon release	2,793	2,793	2,793	2,793	2,793	2,793	2,793
Total	***11,656***	***10,998***	***11,349***	***10,983***	***11,504***	***11,326***	***11,872***

[13] As explained in Chapter 3, the apparent decrease may be in part an artifact of changes in EIA methodology for reporting industrial consumption of certain petroleum products typically used for non-energy purposes.

Table 15 - Percentage changes in CO_2 emissions from sources other than fossil fuel combustion, 1991-96 compared to 1990

	1991	1992	1993	1994	1995	1996
Oxidation of carbon monoxide	-1.9%	1.4%	3.8%	7.5%	9.2%	13.0%
Transportation	-1.0%	2.5%	4.3%	8.0%	10.1%	14.3%
Industrial	-8.5%	-6.9%	-0.4%	3.4%	2.1%	3.2%
Non-energy uses of fossil fuels	-36.8%	-29.3%	-32.3%	-28.6%	-29.7%	-27.0%
Industrial sector uses	-42.4%	-33.6%	-37.6%	-34.0%	-35.2%	-32.1%
Transportation sector - lubricants	-10.5%	-8.8%	-7.1%	-2.9%	-3.4%	-2.9%
Limestone use	-3.1%	1.5%	-6.6%	2.8%	-1.5%	8.8%
Cement Production	-4.6%	5.4%	-0.2%	16.3%	7.3%	13.4%
Lime Manufacture	-0.1%	-1.2%	-14.1%	-11.6%	-11.6%	8.2%
Decomposition of agricultural lime	-5.3%	-6.4%	-11.0%	-10.2%	-7.6%	-7.7%
Land use changes	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	***-5.7%***	***-2.6%***	***-5.8%***	***-1.3%***	***-2.8%***	***1.9%***

Sequestration from forest biomass growth

The total biomass in Missouri forests continued to increase in the 1990s, resulting in substantial annual sequestration of carbon in new biomass. The *1990 Inventory* estimated that biomass growth in Missouri's forests sequestered between 31.3 and 37.8 million tons of CO_2. This study estimates that Missouri's growing forests continued to add new biomass and sequester new carbon in 1996 at nearly the same level as in 1990.

However, this study does estimate that *net* forest sequestration decreased by about 1.3 million tons (STCDE) between 1990 and 1996. Since a 1-ton decrease in carbon sequestration has the same impact as a 1-ton increase in carbon emissions, this is equivalent to a 1.3 million ton increase in CO_2 emissions.

Underlying this decrease in forest sequestration was an increase in the rate of commercial forest harvest and "forest removals" in Missouri between 1990-96. The *State Workbook* recommends a simple methodology for accounting for the carbon impact of forest removals, and the estimate of a 1.3 million ton decrease was derived using this simple methodology.

As discussed in Chapter 6, the methodology recommended in the *State Workbook* and used in this study is based on simplifying assumptions about what happens to carbon in wood and other biomass that is removed from the forest. The net result of these assumptions is that the carbon in forest removals is assumed to be immediately released.

Chapter 6 presents the rational for using this simple methodology despite its limitations. As explained in Chapter 6, researchers are attempting to develop a more sophisticated methodology for use in national studies that attempts to estimate variable rates of carbon release for different portions of the forest removal stream. Use of this more sophisticated methodology would probably result in a smaller estimate (less than 1.3 million tons) of the decrease in Missouri forest sequestration. However, for reasons detailed in Chapter 6, use of the more sophisticated methodology was impractical.

Table 16 - Trends in sequestration of CO_2 emissions due to Missouri forest growth, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996
Biomass growth	(34,615)	(34,615)	(34,615)	(34,615)	(34,615)	(34,615)	(34,615)
Forest removals	7541	7,654	7,954	8,256	8,559	8,726	8,883
Total CO_2 Sequestered	***(27,074)***	***(26,961)***	***(26,662)***	***(26,359)***	***(26,056)***	***(25,889)***	***(25,732)***

Emissions of greenhouse gases other than CO_2

Apart from changes in energy-related CO_2 emissions, the most significant change in Missouri's GHG emissions between 1990 and 1996 was a reduction in perfluorinated carbon (PFC) emissions. PFC emissions in 1996 were about 14 percent of the 1990 level. The largest reduction came in 1990 and 1991, when PFC emissions dropped by about 2.5 million tons (STCDE) to about 31 percent of the 1990 level. This reduction was the leading cause of the drop in Missouri's net GHG emissions in 1990 and 1991.[14]

The reductions in PFC emissions were the result of production line improvements by Noranda Aluminum Inc., whose aluminum manufacturing facility is the sole source of PFC emissions in Missouri. Noranda Aluminum is a participant in USEPA's Voluntary Aluminum Industry Partnership program.

Estimated methane emissions increased by about 9.4 percent to total about 18.3 million tons (STCDE) in 1996, an average annual growth rate of 1.5 percent. Increases occurred primarily after 1994. Estimated methane emissions increased about 6.7 percent from agriculture and about 15.9 percent from landfills.

Estimated nitrous oxide emissions from the use of nitrogenous fertilizers were only slightly higher in 1996 than in 1990.

[14] A portion (about 1.7 MSTCDE) of the reported 1990-91 decline may be an artifact of EIA State Energy Data System data series adjustments for petroleum consumed in the industrial sector. This issue is discussed in Chapter 2, Part 2, Section 3 of this report.

Table 17 summarizes the study's estimates of methane, nitrous oxide and perfluorinated carbons emissions between 1990 and 1996:

Table 17 - Trends in Missouri methane, nitrous oxide and PFC emissions, 1990-96

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1991	1992	1993	1994	1995	1996
Methane emissions	16,712	16,762	17,056	17,569	18,343	18,159	18,290
Agriculture	10,463	10,255	10,410	10,796	11,445	11,140	11,166
Municipal waste	5,604	5,851	5,997	6,135	6,261	6,375	6,481
Fossil fuel prod'n & dist'n	501	513	506	495	494	501	501
Highway transportation	143	143	143	143	143	143	143
Nitrous oxide emissions	3,805	3,859	3,925	4,001	3,877	3,855	3,820
Agriculture	2,333	2,388	2,454	2,530	2,406	2,383	2,348
Highway transportation	1,080	1,080	1,080	1,080	1,080	1,080	1,080
Nitric acid production	391	391	391	391	391	391	391
PFCs aluminum production	4,611	1,431	1,090	1,157	1,049	1,065	641
CF_4 emissions	3,847	1,194	910	965	875	889	535
C_2F_6 emissions	763	237	181	192	174	176	106
Total non-CO_2 emissions	***25,127***	***22,053***	***22,071***	***22,727***	***23,269***	***23,079***	***22,751***

Table 18 - Percentage changes in non-CO_2 emissions in 1991-96 compared to 1990

	1991	1992	1993	1994	1995	1996
Methane emissions	0.3%	2.1%	5.1%	9.8%	8.7%	9.4%
Agriculture	-2.0%	-0.5%	3.2%	9.4%	6.5%	6.7%
Municipal waste	4.4%	7.0%	9.5%	11.7%	13.8%	15.6%
Fossil fuel prod'n & dist'n	2.4%	0.9%	-1.2%	-1.5%	-0.1%	-0.1%
Highway transportation	n/a	n/a	n/a	n/a	n/a	n/a
Nitrous oxide emissions	1.4%	3.2%	5.2%	1.9%	1.3%	0.4%
Agriculture	2.3%	5.2%	8.4%	3.1%	2.1%	0.6%
Highway transportation	n/a	n/a	n/a	n/a	n/a	n/a
Nitric acid production	n/a	n/a	n/a	n/a	n/a	n/a
PFCs aluminum production	-69.0%	-76.4%	-74.9%	-77.3%	-76.9%	-86.1%
CF_4 emissions	-69.0%	-76.4%	-74.9%	-77.3%	-76.9%	-86.1%
C_2F_6 emissions	-69.0%	-76.4%	-74.9%	-77.3%	-76.9%	-86.1%
Total non-CO_2 emissions	***-12.2%***	***-12.2%***	***-9.6%***	***-7.4%***	***-8.2%***	***-9.5%***

Part 4: Projections of Missouri GHG emissions through 2015

Increasing fossil fuel combustion in Missouri is projected to be the driving force behind increases in statewide GHG emissions through 2015. GHG emissions from fossil fuel combustion in Missouri increased between 1990 and 1996 and are projected to increase even further through 2015. Because the amount of increase depends on a variety of factors, Part 4 presents a range of estimates for the amount that fuel-based GHG emissions will increase.

Total GHG emissions from other Missouri sources are not projected to increase significantly between 1996 and 2015. Increases in emissions from some sources such as limestone use and swine and beef operations will, according to this study's projections, be offset by decreases in other sources such as landfills and dairy operations. Combined with pre-1996 decreases in PFC emissions from aluminum manufacture, the net result is that total GHG emissions from non-fuel sources in 2015 are projected to be only slightly higher than they were in 1990.

Section 1: Projected CO_2 emissions from fossil fuel combustion

This study uses scenarios to take into account uncertainties inherent in projecting future greenhouse gas emissions from fossil fuel combustion. Uncertainties influence estimates of future production and consumption of electricity, a secondary form of energy, as well as the consumption of primary forms of energy through combustion of petroleum, coal and natural gas.

In order to accommodate uncertainties affecting the consumption of primary forms of energy, the study projects CO_2 emissions from fossil fuel combustion using three alternative methods, as follows:

- The "steady state" (SS) method assumes that current patterns of energy use will continue in the future. This scenario assumes that in the year 2015 Missouri citizens and businesses will continue to use primary energy resources as they do now. Projections of energy use and GHG emissions under the steady state scenario assume that CO_2 emissions will grow at the same rate as projected population or projected gross state product (GSP).

- The "continuing trends" (CT) method assumes that recent trends in Missouri's energy use continue into the future. The projections rely on estimating future energy use from past energy consumption trends.

- The AEO method assumes that Missouri's future energy consumption will mirror energy use projections made in the *Annual Energy Outlook 1997*, published by the U.S. Department of Energy's Energy Information Administration (USDOE/EIA).

Energy use patterns respond to factors such as economic and demographic shifts, technological change, the discovery or exhaustion of energy resources, and changes in tastes and preferences. Scenarios based on the SS method do not incorporate these factors into projections of energy use or CO_2 emissions sectors. For the sake of completeness, SS projections are presented for all energy use sectors; however, they are useful primarily as reference points rather than reliable projections.

The CT method implicitly incorporates factors that have operated in the past but does not explicitly analyze how changes in these or other factors might affect energy use in the future. CT projections provide a first approximation of future energy use or emissions and help define boundary conditions for more explicit analyses.

The EIA's *Annual Energy Outlook 1997* is based on the National Energy Modeling System (NEMS) developed by the EIA. NEMS provides national- and regional-level "business-as-usual" estimates of energy use that explicitly incorporate assumptions about future economic, demographic and technological change.[15]

Chapter 4 applies the three methods to estimates of future CO_2 emissions from combustion of petroleum, coal and natural gas in each end-use sector, resulting in the projections summarized in Table 19. As Table 19 indicates, the three methods converge for many sector/fuel combinations and also for the CT and AEO estimates for aggregate emissions.

[15] This study draws on the EIA modeling primarily because of the openness of the modeling process and ready availability of its results. The *Annual Energy Outlook 1997* discusses and summarizes projections from other organizations such as DRI, GRI and WEFA. Although these organizations project energy use based on explicit models, the models and results are proprietary and not available to this project.

Table 19 - Projections of end-use sector CO_2 emissions from primary fossil fuel combustion in 2015, by sector

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	CT	SS	AEO
Transportation	58,842	53,303	52,250
Gasoline	33,831	30,186	29,332
Diesel	15,595	14,572	13,612
Jet fuel	9,052	8,158	8,398
Other	365	388	908
Commercial	5,590	5,886	5,341
Natural gas	4,620	4,583	4,214
Petroleum	127	942	784
Coal	843	360	343
Industrial	7,754	15,334	13,202
Natural gas	4,103	5,640	5,091
Petroleum	3,118	5,936	5,272
Coal	533	3,758	2,839
Residential	9,022	10,528	9,563
Natural gas	6,927	8,596	8,558
Petroleum	1,640	1,738	814
Coal	455	194	191
Total end-use sectors	***81,209***	***85,050***	***80,356***

However, Table 19 also reveals significant differences in projections for specific sectors such as transportation and industry. For example, the CT projection for transportation CO_2 emissions in 2015 is about 8 million tons higher than the AEO projection. As Chapter 4 explains, the continuing trend method assumes motor gasoline use will continue growing at a steady rate of about 1 percent per year. In contrast, the national and regional projections in the *Annual Energy Outlook 1997* imply that state motor gasoline use will grow more slowly than during the past, with absolute and per capita consumption decreasing after about 2010. CT projections for diesel and jet fuel growth are also larger than AEO projections.

On the other hand, the CT method projects that industrial CO_2 emissions in 2015 will be lower than in 1990, led by decreases in emissions from petroleum and coal use. AEO projections for the industrial sector indicate that CO_2 emissions from petroleum and coal will increase through 2015. Both methods project that CO_2 emissions from natural gas will increase, but the AEO projection for 2015 is about 1 million tons greater than the CT projection.

Chapter 3 is dedicated to projecting utility CO_2 emissions. The study dedicates a separate chapter to utility sector projections due to the following characteristics of that sector:

1. The utility sector is the largest source of CO_2 emissions in Missouri.

2. Projections of utility energy use and CO_2 emissions are currently subject to high uncertainty due to the prospect of market restructuring. The sector is likely to undergo restructuring within the next few years, but the nature of the restructuring is a political decision that has not yet been determined.

3. Electricity is a secondary form of energy. Projecting energy use in the utility sector requires an additional level of analysis because utility consumption of primary fossil fuel energy is partly derived from end use-demand for electricity.

Table 20 summarizes the result of applying the SS, CT and AEO methods to estimate CO_2 emissions from future utility use of coal, petroleum and natural gas.

Table 20 - "Direct" projections of utility sector CO_2 emissions from primary fossil fuel combustion in 2015

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	AEO	CT	SS
Utility sector	80,576	73,893	68,516
Coal	78,584	72,957	68,083
Natural gas	1,781	862	308
Petroleum	211	74	125
End-use sectors	80,356	81,209	85,050
Total - all sectors	***160,932***	***155,102***	***153,566***

The direct estimation methods used for Table 20 are probably not adequate to project utility emissions because they do not incorporate electricity users' demand for electricity. Chapter 3 extends the analysis of utility CO_2 emissions, developing four extended scenarios based on the derived nature of utility primary fossil fuel use and CO_2 emissions. These scenarios, summarized in Table 21, are based on a two-step estimation procedure described in Chapter 3.

Table 21 - Extended Method Scenarios for utility sector CO_2 emissions from primary fossil fuel combustion in 2015

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	AEO Sales		CT Sales	
	High NG	**Low NG**	**High NG**	**Low NG**
Utility sector	74,224	80,877	82,131	88,621
Coal	68,534	78,995	76,468	87,685
Natural gas	5,589	1,781	5,589	862
Petroleum	102	102	74	74
End-use sectors	80,356	80,356	81,209	81,209
Total - all sectors	***154,580***	***161,233***	***163,339***	***169,830***

Future electricity sales is the first differentiating factor in the extended methodology. The two leftmost projections in Table 21 are based on AEO estimates of future electricity sales; the two rightmost are based on CT estimates. The "AEO sales" projections are lower than the "CT sales" projections because the *Annual Energy Outlook 1997* states that utility sales will grow more slowly than in the past. The CT and AEO methods for estimating utility sales are fully described in Chapter 3.

Projected utility investment and use of new natural gas generation is the second differentiating factor in the extended methodology. Substitution of natural gas for coal would decrease CO_2 emissions because coal has higher carbon content than natural gas. The "high NG" projections assume that utilities (or new independent power producers entering the market under deregulation) will increase the rate of investment in natural gas generating facilities and expand the use of natural gas to mid-load or base-load generation. The "low NG" projections assume that Missouri utilities will continue to confine natural gas use to meeting peak load requirements.

The "business-as-usual" projections in Table 21 are based on conservative assumptions about future end user decisions and utility decisions. The electricity sales projections assume growth rates equal or lower than the sales growth rates used by Missouri utilities in their Integrated Resource Plans. The level chosen to represent a "high" use of natural gas is based on *Annual Energy Outlook 1997* projections.

Moreover, the study makes conservative assumptions about the impact of restructuring on external purchases and sales of electricity in order to keep the scope of its analytic effort within reasonable bounds. The projections in Table 21 assume that the close relationship between the quantity of electricity produced and consumed in Missouri will continue. Restructuring could alter this relationship and bring large increases in exports and/or imports of electricity.

The aggregate projections for CO_2 emissions from energy use summarized in Table 20 and Table 21 may be classified into low-, midrange- and high-emissions scenarios, as follows:

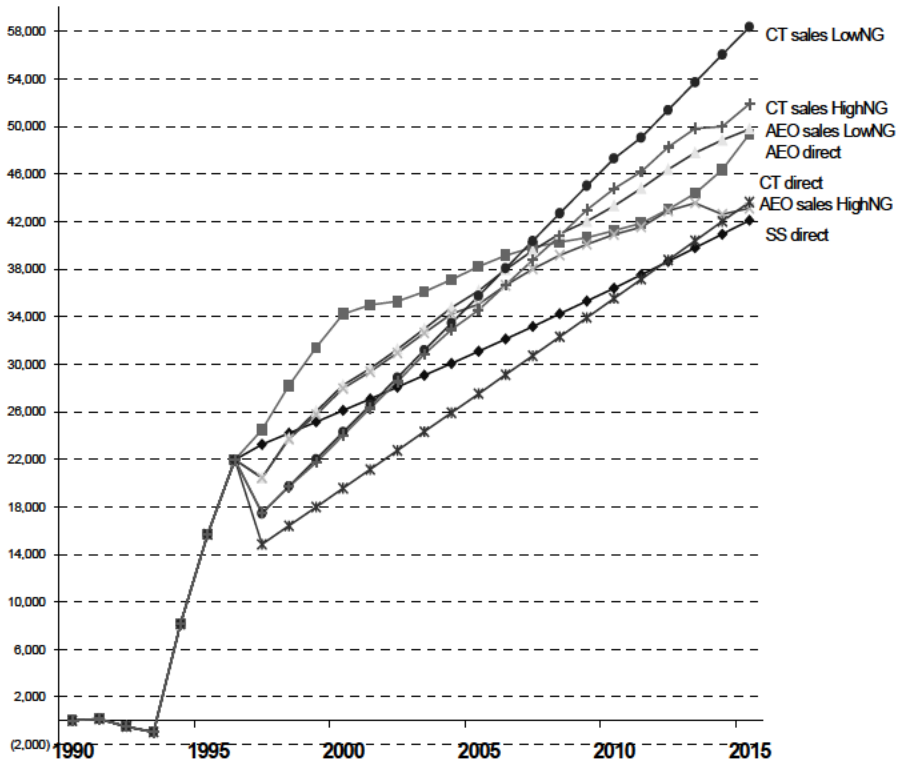
- ***Low-emissions scenario:*** Total emissions of about 154 to 155 million tons of CO_2. The CT direct estimate and the AEO sales/high natural gas estimate, both in Table 21, fit into this scenario.

- ***Midrange-emissions scenario:*** Total emissions of about 161 to 163 million tons of CO_2. The AEO direct estimate in Table 20 and the AEO sales/low natural gas and CT sales/high natural gas estimates in Table 21 fit into this scenario.

- ***High-emissions scenario:*** Total emissions of about 170 million tons of CO_2. The CT sales/low natural gas estimate in Table 21 fit into this scenario.

Under the low emissions scenario, CO_2 emissions from energy use would increase at an average annual growth rate of about 1.3 percent per year between 1990 and 2015, resulting in an increase of 42 to 44 million tons over 1990 levels. The corresponding average annual growth rates for the midrange and high scenarios are about 1.5 percent (an increase of 49 to 51 million tons) and 1.7 percent (58 million tons). Chart 4 depicts projected increases in CO_2 emissions deriving from the different scenarios.

Chart 6 - Projected increase in CO_2 from fossil fuel combustion, 1990-2015



Although the seven different projections for the year 2015 appear to group themselves into low-, midrange- and high-emissions scenarios, this is not necessarily true for earlier years. For example, projections based on the Continuing Trend method are relatively low[16] and those based on EIA's *Annual Energy Outlook 1997* are relatively high for earlier years. However, EIA projects a decreasing growth rate in energy use after the year 2000. Therefore, after the year 2000, the AEO projections are bypassed by the CT projections, which do not assume a decreasing growth rate.

Tables 22 through 24 summarize Missouri greenhouse gas emissions projections for 2005, 2010 and 2015. These tables include all CO_2 sources and sinks, non-energy as well as energy. They also summarize projected emissions of methane, nitrous oxide and PFCs.

[16] The CT projections appear to project a decrease in emissions in the years immediately following 1996. This is an artifact of the use of linear regression. As explained in Chapter 2, the CT method's short-term projections should be disregarded.

Table 22 - Estimated Missouri GHG emissions in 2005, by scenario and method

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	Low emissions scenarios			Midrange			High
	SS Direct	AEO Sales High NG	CT Direct	AEO Direct	AEO Sales Low NG	CT Sales High NG	CT Sales Low NG
Fossil fuel combustion	142,546	146,494	138,974	149,681	147,632	146,019	147,221
Transportation	48,183	49,821	50,326	49,821	49,821	50,326	50,326
Gasoline	29,037	29,305	30,646	29,305	29,305	30,646	30,646
Diesel	12,035	12,461	12,421	12,461	12,461	12,421	12,421
Jet	6,738	7,398	6,897	7,398	7,398	6,897	6,897
Other	373	658	362	658	658	362	362
Commercial	30,587	30,891	31,282	32,055	31,306	34,078	34,554
Electricity	24,925	25,568	25,956	26,733	25,984	28,751	29,228
Nat. Gas	4,409	4,179	4,251	4,179	4,179	4,251	4,251
Petroleum	906	810	438	810	810	438	438
Coal	346	334	637	334	334	637	637
Industrial	27,570	28,853	22,444	29,626	29,129	23,904	24,153
Electricity	14,906	16,980	13,553	17,754	17,256	15,013	15,262
Nat. Gas	4,658	4,623	3,838	4,623	4,623	3,838	3,838
Petroleum	4,903	4,594	3,474	4,594	4,594	3,474	3,474
Coal	3,104	2,655	1,579	2,655	2,655	1,579	1,579
Residential	36,206	36,930	34,921	38,178	37,376	37,711	38,187
Electricity	26,079	27,424	25,904	28,672	27,870	28,694	29,170
Nat. Gas	8,269	8,225	7,108	8,225	8,225	7,108	7,108
Petroleum	1,672	1,099	1,565	1,099	1,099	1,565	1,565
Coal	187	182	344	182	182	344	344
Other sources of CO_2	12,588	12,602	12,604	12,602	12,602	12,604	12,604
Methane emissions	15,357	15,357	15,357	15,357	15,357	15,357	15,357
Nitrous oxide emissions	3,872	3,872	3,872	3,872	3,872	3,872	3,872
PFC emissions	458	458	458	458	458	458	458
Forest sequestration	(24,140)	(24,140)	(24,140)	(24,140)	(24,140)	(24,140)	(24,140)
Total GHG emissions	***150,681***	***154,644***	***147,125***	***157,830***	***155,781***	***154,170***	***155,372***

Table 23 - Estimated Missouri GHG emissions in 2010, by scenario and method

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	Low emissions scenarios				Midrange		High
	SS Direct	AEO Sales High NG	CT Direct	AEO Direct	AEO Sales Low NG	CT Sales High NG	CT Sales Low NG
Fossil fuel combustion	147,869	152,379	146,999	152,711	154,783	156,239	158,771
Transportation	50,641	51,554	54,545	51,554	51,554	54,545	54,545
Gasoline	29,604	29,509	32,199	29,509	29,509	32,199	32,199
Diesel	13,243	13,204	14,008	13,204	13,204	14,008	14,008
Jet	7,414	8,022	7,974	8,022	8,022	7,974	7,974
Other	380	818	364	818	818	364	364
Commercial	31,476	32,174	33,793	32,295	33,052	37,552	38,582
Electricity	25,704	26,845	28,335	26,966	27,723	32,094	33,124
Nat. Gas	4,495	4,193	4,435	4,193	4,193	4,435	4,435
Petroleum	924	798	283	798	798	283	283
Coal	353	339	740	339	339	740	740
Industrial	29,035	30,671	22,191	30,753	31,265	24,031	24,535
Electricity	15,100	18,169	13,869	18,251	18,763	15,708	16,213
Nat. Gas	5,125	4,903	3,970	4,903	4,903	3,970	3,970
Petroleum	5,395	4,893	3,296	4,893	4,893	3,296	3,296
Coal	3,415	2,706	1,056	2,706	2,706	1,056	1,056
Residential	36,717	37,980	36,469	38,109	38,912	40,111	41,108
Electricity	26,392	28,466	27,449	28,594	29,397	31,091	32,089
Nat. Gas	8,430	8,390	7,017	8,390	8,390	7,017	7,017
Petroleum	1,704	938	1,603	938	938	1,603	1,603
Coal	191	187	399	187	187	399	399
Other sources of CO_2	12,995	12,967	13,034	12,967	12,967	13,034	13,034
Methane emissions	15,150	15,150	15,150	15,150	15,150	15,150	15,150
Nitrous oxide emissions	3,870	3,870	3,870	3,870	3,870	3,870	3,870
PFC emissions	437	437	437	437	437	437	437
Forest sequestration	(23,305)	(23,305)	(23,305)	(23,305)	(23,305)	(23,305)	(23,305)
Total GHG emissions	***157,016***	***161,497***	***156,185***	***161,830***	***163,902***	***165,425***	***167,957***

Table 24 - Estimated Missouri GHG emissions in 2015, by scenario and method

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	Low emissions scenarios			Midrange			High
	SS Direct	AEO Sales High NG	CT Direct	AEO Direct	AEO Sales Low NG	CT Sales High NG	CT Sales Low NG
Fossil fuel combustion	153,566	154,580	155,102	160,822	161,233	163,339	169,830
Transportation	53,303	52,250	58,842	52,250	52,250	58,842	58,842
Gasoline	30,186	29,332	33,831	29,332	29,332	33,831	33,831
Diesel	14,572	13,612	15,595	13,612	13,612	15,595	15,595
Jet	8,158	8,398	9,052	8,398	8,398	9,052	9,052
Other	388	908	365	908	908	365	365
Commercial	32,208	32,153	36,275	34,408	34,556	39,696	42,391
Electricity	26,322	26,812	30,685	29,067	29,215	34,106	36,801
Nat. Gas	4,583	4,214	4,620	4,214	4,214	4,620	4,620
Petroleum	942	784	127	784	784	127	127
Coal	360	343	843	343	343	843	843
Industrial	30,630	31,807	21,962	33,371	33,474	23,546	24,794
Electricity	15,297	18,605	14,208	20,170	20,273	15,792	17,040
Nat. Gas	5,640	5,091	4,103	5,091	5,091	4,103	4,103
Petroleum	5,936	5,272	3,118	5,272	5,272	3,118	3,118
Coal	3,758	2,839	533	2,839	2,839	533	533
Residential	37,425	38,370	38,023	40,793	40,952	41,255	43,803
Electricity	26,897	28,807	29,000	31,230	31,389	32,233	34,780
Nat. Gas	8,596	8,558	6,927	8,558	8,558	6,927	6,927
Petroleum	1,738	814	1,640	814	814	1,640	1,640
Coal	194	191	455	191	191	455	455
Other sources of CO_2	13,415	13,310	13,472	13,310	13,310	13,472	13,472
Methane emissions	15,109	15,109	15,109	15,109	15,109	15,109	15,109
Nitrous oxide emissions	3,868	3,868	3,868	3,868	3,868	3,868	3,868
PFC emissions	416	416	416	416	416	416	416
Forest sequestration	(22,503)	(22,503)	(22,503)	(22,503)	(22,503)	(22,503)	(22,503)
Total GHG emissions	***163,872***	***164,781***	***165,465***	***171,024***	***171,434***	***173,702***	***180,193***

Table 25 - Projected average annual growth rate of CO_2 emissions from fossil fuel combustion in Missouri, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

Projected CO_2 emissions

		1990	1996	2000	2005	2010	2015
Low	SS direct	111,472	133,411	137,577	142,546	147,869	153,566
	AEO sales HighNG	111,472	133,410	139,422	146,494	152,379	154,580
	CT direct	111,472	133,411	131,027	138,974	146,999	155,102
Mid	AEO direct	111,473	133,410	145,672	149,681	152,711	160,822
	AEO sales LowNG	111,473	133,410	139,689	147,632	154,783	161,233
	CT sales HighNG	111,472	133,411	135,473	146,019	156,239	163,339
High	CT sales LowNG	111,472	133,411	135,748	147,221	158,771	169,830

Projected increase in CO_2 emissions

		1996	2000	2005	2010	2015
Low	SS direct	21,939	26,105	31,073	36,396	42,094
	AEO sales HighNG	21,938	27,950	35,022	40,906	43,108
	CT direct	21,939	19,554	27,502	35,527	43,630
Mid	AEO direct	21,937	34,199	38,207	41,238	49,349
	AEO sales LowNG	21,937	28,216	36,159	43,310	49,760
	CT sales HighNG	21,939	24,001	34,547	44,767	51,867
High	CT sales LowNG	21,939	24,276	35,748	47,299	58,357

Projected average annual growth rate

		Growth rate 1990-1996	Growth rate 1996-2000	Growth rate 2000-2005	Growth rate 2005-2010	Growth rate 2010-2015
Low	SS direct	3.0%	0.8%	0.7%	0.7%	0.8%
	AEO sales HighNG	3.0%	1.1%	1.0%	0.8%	0.3%
	CT direct	3.0%	-0.4%	1.2%	1.1%	1.1%
Mid	AEO direct	3.0%	2.2%	0.5%	0.4%	1.0%
	AEO sales LowNG	3.0%	1.2%	1.1%	1.0%	0.8%
	CT sales HighNG	3.0%	0.4%	1.5%	1.4%	0.9%

Section 2: Projected GHG emissions from sources other than energy use

About 25 percent of greenhouse gas emissions come from sources other than fossil fuel combustion. In 1990, these "other" sources emitted a total of about 36.8 million tons (STCDE) of greenhouse gas emissions, consisting of about 11.7 million tons of CO_2, 16.7 million tons (STCDE) of methane (CH_4), 3.8 million tons (STCDE) of nitrous oxide (N_2O) and 4.6 million tons (STCDE) of perfluorinated carbons (PFCs).[17]

By 2015, the share of these sources in total greenhouse gas emissions is projected to decline due to a projected 2.5 million ton (STCDE) decrease in total emissions from these sources as well as projected increases in CO_2 emissions from fossil fuel combustion.

However, increases are projected through 2015 for some of these sources, particularly the following:

1. In 2015, CO_2 emissions from industrial and agricultural uses of limestone are projected at a level about 1.4 million tons higher than in 1990. As shown below, the increase is expected to occur steadily throughout the period.

Units: Short Tons Carbon Dioxide (CO_2)

	1990	**2000**	**2005**	**2010**	**2015**
Clinker production	2,256,657	2,801,127	3,103,127	3,405,127	3,707,127
Masonry cement	2,845	2,845	2,845	2,845	2,845
Lime Production	1,599,045	1,730,627	1,730,627	1,730,627	1,730,627
Agricultural Lime	586,005	459,109	467,661	461,797	461,797
Total	4,444,551	4,993,707	5,304,259	5,600,395	5,902,395
Growth rate		***1.2%***	***1.2%***	***1.2%***	***1.1%***

2. In 2015, methane emissions from swine operations are projected at a level about 0.9 million tons higher than in 1990. As shown below, emissions from this source are likely to peak around the year 2005 and then decrease as swine numbers decline.

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

1990	**1995**	**2000**	**2005**	**2010**	**2015**
2,747	3,401	3,691	3,906	3,776	3,672
Average annual growth rate since 1990		***3.0%***	***2.4%***	***1.6%***	***1.2%***

[17] As explained earlier in this chapter, Short Tons Carbon Dioxide Equivalent (STCDE) as a unit of measure functions to permit comparisons between different greenhouse gases. For example, 1 million tons (STCDE) of methane, released into the atmosphere, is expected to have an effect on average temperature equivalent to the effect of releasing 1 million tons of CO_2.

3. In 2015, methane emissions from beef operations are projected at a level about 0.7 million tons (STCDE) higher than in 1990. Although emissions will be affected by the beef cycle, an increase is expected through most of the period.

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1995	2000	2005	2010	2015
Total	5,677	5,956	5,636	6,074	6,210	6,420
Growth rate			***-0.1%***	***0.7%***	***0.9%***	***1.2%***

The projected increases in GHG emissions from these sources are expected to be more than offset by decreases in GHG emissions from other sources. Chart 7 illustrates the net effect of decreases from some sources, more than offsetting increases from other sources. Sources with major decreases projected through 2015 are as follows:

1. In 2015, PFC emissions from aluminum manufacture are projected at a level about 4.2 million tons (STCDE) lower than 1990 PFC emissions. Most of this decrease was realized between 1990 and 1992, when Noranda Aluminum, whose aluminum manufacturing plant is the sole source of PFC emissions in Missouri, reduced PFC emissions by about 3.5 million tons (STCDE) through improvements in its manufacturing process. Noranda achieved this reduction as part of its participation in the Voluntary Aluminum Industry Partnership (VAIP) program sponsored by USEPA. The emissions estimates below are base estimates of PFC emissions for 1990 through 1996 and projections for 2005 and 2015 provided by Noranda.

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1995	2005	2015
CF_4	3,847	889	382	347
C_2F_6	763	176	76	69
Total PFCs	4,611	1,065	458	416
Growth rate			***-14%***	***-9%***

2. In 2015, methane emissions from landfills are projected at a level about 0.7 million tons (STCDE) lower than emissions in 1990. Landfill emissions have increased since 1990 and are projected to increase until the year 2000, but beginning in that year, federal and state requirements that should affect about half of Missouri's landfills will lead to a large increase in methane flaring and capture. Landfill emissions will also show the effect of efforts to reduce municipal waste disposal, efforts which began in 1991 in response to a state mandate. The complicated pattern of landfill emissions is traced below;

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1995	2000	2005	2010	2015
Low WIP	3,906	4,678	3,803	4,131	4,037	3,792
High WIP	7,374	8,097	6,187	6,368	6,130	5,871
Midpoint	5,501	6,273	4,930	5,205	5,046	4,788
Growth rate			***-1.1%***	***-0.4%***	***-0.4%***	***-0.6%***

3. In 2015, methane emissions from dairy operations are projected at a level about 1.1 million tons (STCDE) lower than emissions in 1990.

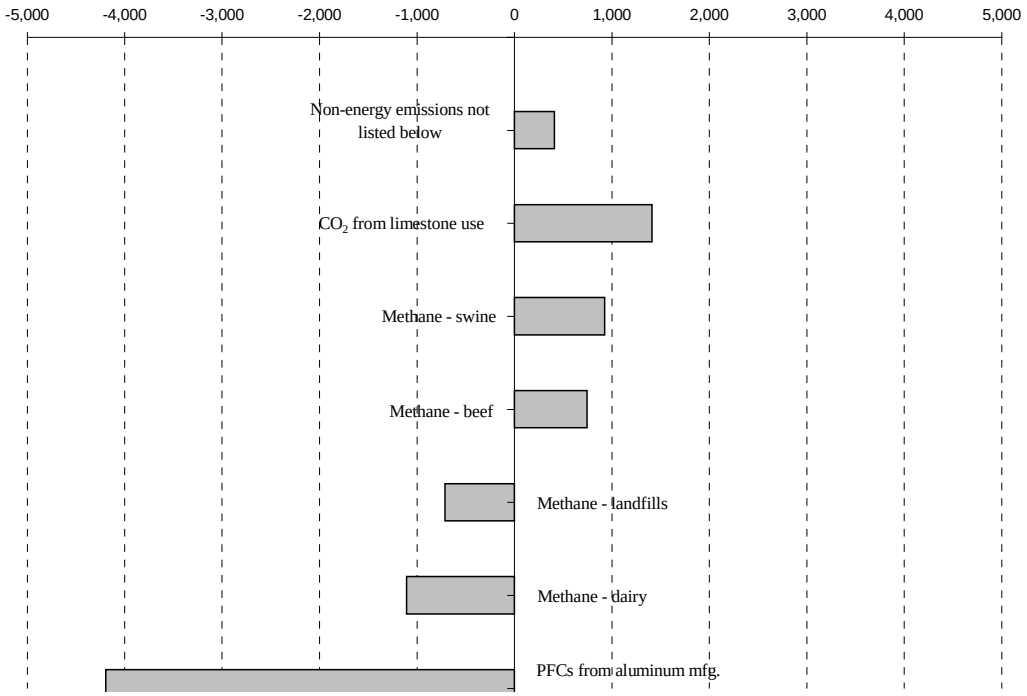
Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1995	2000	2005	2010	2015
Total	1,808	1,552	1,238	1,023	852	700
			-14.1%	***-15.7%***	***-17.3%***	***-18.9%***

While emissions from these three sources are projected to decrease by a total of about 6 million tons (STCDE), most of the decrease in PFC emissions occurred early after 1990, whereas the decrease in landfill emissions is projected to occur after the year 2000.

Chart 7 - Projected change in GHG emissions, for all GHG emissions sources except fossil fuel combustion, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE), Increase or Decrease



Although the chart illustates that methane emissions in 2015 will be about equal to those in 1990, it is important to recognize that the role that methane sources will play after the year 2000 is different from their role before that year. To date, increases in methane emissions have offset a portion of the decrease in PFC emissions. Through 1996, methane emissions from landfills increased by about 0.9 million tons (STCDE) and methane emissions from swine and beef operations increased by about 1 million tons (STCDE).

After the year 2000, methane sources are projected to drive the decrease in overall emissions. Methane emissions from landfills are projected to decrease by 1.6 million tons (STCDE). Methane emissions from livestock operations are also projected to decrease, with a 0.6 million ton (STCDE) increase in methane emissions from swine and beef operations being offset by a 0.8 million ton decrease from dairy operations. These decreases are expected to occur due to an increase in the flaring and capture of landfill methane, a slowdown in the growth of swine operations in Missouri and continued decline of the state's dairy industry.

Table 26 summarizes the study's net projections for non-energy greenhouse gas emissions from all sources. The projected annual average growth rate for all sources equals about 0.3 percent per year.

Table 26 - Estimated GHG emissions from Missouri sources other than fossil fuel combustion, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1996	2000	2005	2010	2015
CO_2 emissions excluding energy	11,656	11,872	12,169	12,595	12,984	13,357
Oxidation of carbon monoxide	1,460	1,650	1,733	1,810	1,857	1,877
Transportation	1,293	1,477	1,549	1,616	1,653	1,662
Industrial sector	168	173	184	194	204	215
Non-energy uses of fossil fuels	1,345	982	1,036	1,074	1,120	1,171
Industrial sector uses	1,111	754	803	835	875	920
Transportation use of lubricants	234	228	233	239	245	251
Limestone use	4,445	4,834	4,994	5,304	5,600	5,902
Cement Production	2,260	2,562	2,804	3,106	3,408	3,710
Lime Manufacture	1,599	1,731	1,731	1,731	1,731	1,731
Decomposition of agricultural lime	586	541	459	468	462	462
Land use changes	4,407	4,407	4,407	4,407	4,407	4,407
Net loss of above-ground "sinks"	1,613	1,613	1,613	1,613	1,613	1,613
Soil carbon release	2,793	2,793	2,793	2,793	2,793	2,793
Methane emissions	16,712	18,290	16,472	17,185	16,861	16,557
Agriculture	10,463	11,166	10,796	11,234	11,068	11,023
Beef cattle operations	5,677	6,161	5,636	6,074	6,210	6,420
Dairy cattle operations	1,808	1,477	1,238	1,023	852	700
Swine operations	2,747	3,296	3,691	3,906	3,776	3,672
Other livestock operations	170	170	170	170	170	170
Rice cultivation	61	61	61	61	61	61
Disposal of crop wastes by burning	0	0	0	0	0	0
Municipal & industrial waste	5,604	6,481	5,033	5,307	5,149	4,890
Municipal & industrial landfills	5,501	6,378	4,930	5,205	5,046	4,788
Municipal waste-water treatment	103	103	103	103	103	103
Fossil fuel production & distribution	501	501	501	501	501	501
Natural gas leakage	496	495	495	495	495	495
Coal mining	6	6	6	6	6	6
Oil production	0	0	0	0	0	0
Highway transportation	143	143	143	143	143	143
Nitrous oxide emissions	3,805	3,820	3,875	3,872	3,870	3,868
Agriculture	2,333	2,348	2,403	2,401	2,399	2,397
Use of nitrogenous fertilizers	2,333	2,348	2,403	2,401	2,399	2,397
Disposal of crop wastes by burning	0	0	0	0	0	0
Highway transportation	1,080	1,080	1,080	1,080	1,080	1,080
Nitric acid production	391	391	391	391	391	391
PFCs from aluminum production	4,611	641	650	458	437	416
CF_4 emissions*	3,847	535	542	382	365	347
C_2F_6 emissions*	763	106	108	76	72	69

See Chapter 5, Part 4.

Forest growth

In 2015, CO_2 sequestration from Missouri forest growth is projected to decrease compared to 1990 due to projected increases in the commercial harvest of forest products. Assuming the middle case for commercial harvest growth, this is equivalent to an emissions increase of 4.6 million tons of CO_2.

Units: 1,000 Short Tons Carbon Dioxide Equilvalent (STCDE)

	1990	**1995**	**2000**	**2005**	**2010**	**2015**
Potential sequestration	34,615	34,615	34,615	34,615	34,615	34,615
Removals						
Low case	7,541	8,726	9,390	10,001	10,588	11,153
Mid point	7,541	8,726	9,606	10,475	11,310	12,112
High case	7,541	8,726	9,822	10,949	12,032	13,071
Net sequestration						
Low case	27,074	25,889	25,225	24,614	24,027	23,462
Mid point	27,074	25,889	25,009	24,140	23,305	22,503
High case	27,074	25,889	24,793	23,666	22,583	21,544
Mid-case growth rate			***-0.8%***	***-0.8%***	***-0.7%***	***-0.7%***

"Net sequestration" in the table refers to the impact of biomass growth minus the impact of forest removals. The rate of net sequestration is projected to decrease because the rate of biomass growth is projected to remain constant and the rate of removals is projected to increase.

The projected 4.6 million ton decrease in net sequestration between 1990 and 2015 is based on a simple methodology that assumes that the carbon in forest removals is immediately released. As discussed above, researchers at the national level are developing a more sophisticated methodology that attempts to estimate variable rates of carbon release for different portions of the forest removal stream. Use of the more sophisticated methodology would probably result in a smaller estimate (less than 4.6 million tons) of the decrease in Missouri forest sequestration. However, as discussed in Chapter 6, use of this more sophisticated methodology was not practical for the present study.

Greenhouse Gas Emission Trends and Projections for Missouri, 1990-2015 Technical Report

Chapter 2

Trends in CO_2 Emissions from Fossil Fuel Combustion in Missouri, 1990-96

Chapter 2: Trends in CO_2 emissions from fossil fuel combustion in Missouri, 1990-96

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Chapter 2: Trends in CO_2 emissions from fossil fuel combustion in Missouri, 1990-96

Part 1: Overview

Between 1990 and 1996, Missouri CO_2 emissions from fossil fuel combustion grew by about 22 million tons, an increase of about 20 percent. As Table 1 indicates, the increase occurred during the last three years of the period. During these three years, total CO_2 emissions from energy use grew about 23 million tons, more than offsetting a reduction in CO_2 emissions that had occurred between 1990 and 1993.

Table 1 - Estimated CO_2 emissions from fossil fuel combustion in Missouri, summary by sector, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996	Change from 1990 base	
Transportation	36,782.4	36,636.2	37,812.6	39,542.0	41,109.7	42,351.5	44,206.8	7,424.4	20.2%
Commercial	4,625.1	4,897.8	4,729.7	5,300.3	5,071.1	4,991.2	5,464.6	839.5	18.2%
Industrial	10,283.9	9,414.1	9,573.8	10,240.7	10,633.8	10,497.3	10,612.4	328.5	3.2%
Residential	8,242.3	8,833.2	8,514.8	9,683.6	8,949.7	9,073.5	9,838.4	1,596.1	19.4%
Utility	51,538.6	51,856.7	50,346.2	45,752.0	53,843.2	60,242.6	63,287.7	11,749.1	22.8%
Total all sectors	***111,472.3***	***111,638.0***	***110,977.1***	***110,518.6***	***119,607.5***	***127,156.1***	***133,410.0***	21,937.7	19.7%

The sectors used in Table 1 and the remainder of Parts 1 through 4 of this chapter are defined as users of *primary* energy resources. Table 1 lists five sectors including utilities that use primary energy resources. Examples of primary energy resources are coal, petroleum and natural gas. Utilities are a unique sector in that they use primary energy resources to produce electricity, which is a *secondary* energy resource.

Part 5 of the chapter employs an alternative classification of sectors. This alternative classification includes only end users of electricity and therefore excludes utilities as a separate sector. It allocates emissions from fossil fuel burned by utilities to the four end use sectors in proportion to their use of electricity. Further explanation of the difference in approach is provided by Table 21 in this chapter.

The primary factor determining changes in energy-based CO_2 emissions from 1990 to 1996 was changing levels of fossil fuel combustion.[1] Table 2 indicates the pattern of energy consumption during the period. Through 1993 there was little change in net fossil fuel energy consumption, but after 1993, energy use increased from about 1,335 trillion Btus to 1,573 trillion Btus, an 18 percent increase in three years.

Table 2 - Net changes in Missouri fossil fuel energy consumption, 1990-96

Units: Trillion Btus

	1990	1991	1992	1993	1994	1995	1996
Total	1,322	1,332	1,321	1,335	1,422	1,497	1,569
Change from previous period		0.7%	-0.8%	1.1%	6.6%	5.3%	4.8%
Change from 1990 base year		0.7%	-0.1%	1.0%	7.6%	13.3%	18.7%

CO_2 emissions increased by almost 12 million tons in the utility sector and more than 7 million tons in the transportation sector between 1990 and 1996. As Table 3 indicates, these two sectors accounted for 88 percent of the increase during the period. CO_2 emissions from coal accounted for more than 99 percent of the utility sector increase, and CO_2 emissions from petroleum-based fuels accounted for more than 99 percent of the increase in the transportation sector.

CO_2 emissions increased 1.6 million tons in the residential sector, 0.8 million tons in the commercial sector and 0.3 million tons in the industrial sector from 1990 to 1996. Together, these three sectors accounted for about 12 percent of the increase during the period, with most of the increase coming from use of natural gas. In the industrial sector, the rise in CO_2 emissions from natural gas use was largely offset by decreased emissions from coal use.

For each sector, Table 3 indicates each fuel's contribution to that sector's net change in CO_2 emissions between 1990 and 1996. For example, transportation CO_2 emissions increased 33 percent between 1990 and 1996. About 36 percent of that net change was due to an increase in jet fuel emissions, 34 percent due to diesel emissions and 30 percent due to emissions from gasoline use. Thus, by 1996 personal travel (gasoline) was still the primary source of CO_2 emissions in transportation, but commercial travel (diesel and jet fuel) was the fastest growing component of the sector's emissions.

[1] In the utility sector, a change in the source of coal also played a role, as described in Part 2 of this chapter.

Table 3 - Estimated CO_2 emissions from fossil fuel combustion in Missouri, detail by sector, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996	Change from Base
Energy end-use sectors	59,934	59,781	60,631	64,767	65,764	66,913	70,122	
Transportation	36,782	36,636	37,813	39,542	41,110	42,351	44,207	34%
Gasoline	25,826	25,810	26,109	26,454	27,125	27,364	28,044	30%
Diesel	7,578	7,245	8,132	8,397	8,959	9,423	10,131	34%
Jet fuel	2,971	3,353	3,362	4,040	4,752	5,204	5,672	36%
Other	408	227	210	652	274	360	359	-1%
Commercial	4,625	4,898	4,730	5,300	5,071	4,991	5,465	4%
Natural gas	3,494	3,710	3,555	4,071	3,876	3,788	4,258	91%
Petroleum	721	823	844	844	865	871	881	19%
Coal	410	365	330	385	330	333	325	-10%
Industrial	10,284	9,414	9,574	10,241	10,634	10,497	10,612	1%
Natural gas	3,077	3,220	3,270	3,417	4,021	3,865	3,921	257%
Petroleum	4,107	3,263	3,580	3,985	4,101	4,044	4,127	6%
Coal	3,100	2,932	2,725	2,839	2,512	2,589	2,564	-163%
Residential	8,242	8,833	8,515	9,684	8,950	9,073	9,838	7%
Natural gas	6,822	7,085	6,802	7,839	7,177	7,281	7,986	73%
Petroleum	1,200	1,552	1,534	1,636	1,595	1,612	1,680	30%
Coal	221	196	178	209	178	180	173	5%
Electric utility sector	51,539	51,857	50,346	45,752	53,843	60,243	63,288	54%
Natural gas	207	746	137	285	252	743	284	1%
Petroleum	93	113	85	182	133	138	117	0%
Coal	51,238	50,997	50,124	45,284	53,458	59,362	62,887	99%
	111,472	111,638	110,977	110,519	119,608	127,156	133,410	100%

Table 4 categorizes CO_2 emissions from fossil fuel combustion into emissions from use of coal, petroleum and natural gas. Between 1990 and 1996, CO_2 emissions from coal use increased by about 11 million tons, petroleum by about 8.1 million tons and natural gas by about 2.8 million tons. As Table 4 indicates, this amounted to about a 20 percent increase for each of the three major fuel types.

Thus, emissions from the three fuel types between 1990 and 1996 increased in rough proportion to their relative importance in 1990. In 1990, about 49.3 percent of energy-based CO_2 emissions came from coal, 38.2 percent from petroleum and 12.5 percent from natural gas. In 1996, these proportions remained about the same.

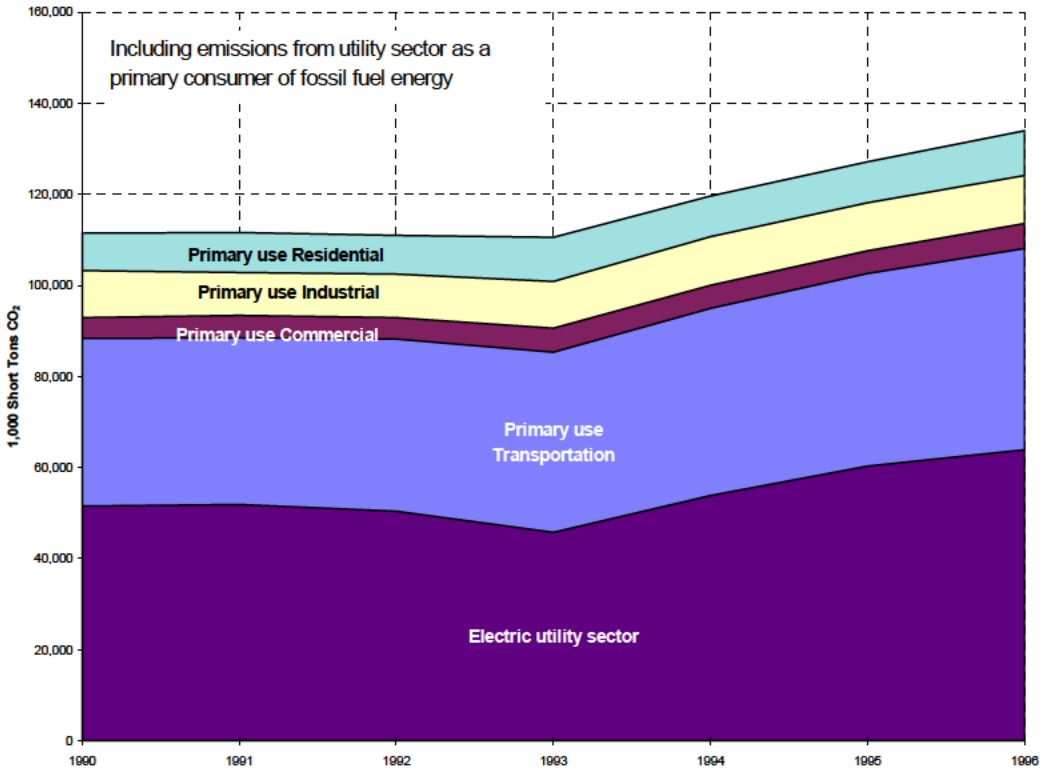
Table 4 - Estimated CO_2 emissions from fossil fuel combustion in Missouri, by fuel type, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996	Change from 1990 base	
Coal	54,969.3	54,490.2	53,356.8	48,717.0	56,479.1	62,463.8	65,949.1	10,979.8	20.0%
Petroleum	42,590.9	42,236.7	43,721.4	45,613.7	47,634.2	48,738.9	50,734.3	8,143.4	19.1%
Natural Gas	13,912.1	14,911.1	13,898.9	16,187.9	15,494.2	15,953.4	16,726.6	2,814.5	20.2%
	111,472.3	111,638.0	110,977.1	110,518.6	119,607.5	127,156.1	133,410.0	21,937.7	19.7%
Change - prev. year		0.1%	-0.6%	-0.4%	8.2%	6.3%	4.9%		

Chart 1 illustrates the distribution of CO_2 emissions during the period across the five primary energy use sectors in Missouri.

Chart 1 - Missouri primary energy-use sector shares of CO_2 emissions from fossil fuel combustion, 1990-96



Parts 2, 3 and 4 of this chapter discuss CO_2 emissions trends from coal, petroleum and natural gas respectively between 1990 and 1996. Part 2 focuses on electric utilities, and Parts 3 and 4 discuss Missouri's other primary energy use sectors. Part 5 switches to an end-use sector framework for summarizing trends in Missouri CO_2 emissions between 1990 and 1996, and Part 6 summarizes methodology used for the estimates.

Part 2: Trends in combustion of coal and associated CO_2 emissions

Utility coal use was the state's leading source of greenhouse gas emissions from 1990 to 1996. Utility CO_2 emissions increased by about 12 million tons during this period, and more than 99 percent of Missouri utility CO_2 emissions came from coal-fired boilers.

Section 1: Trends in energy sources used to generate electricity in Missouri

Coal combustion is the leading source of baseload[2] electric generation in Missouri. As Table 6 indicates, coal's overall role fluctuated somewhat between 1990 and 1996. The share of electricity generated from coal decreased between 1990 and 1993, from about 82 percent to 77 percent, but increased to about 84 percent between 1994 and 1996.

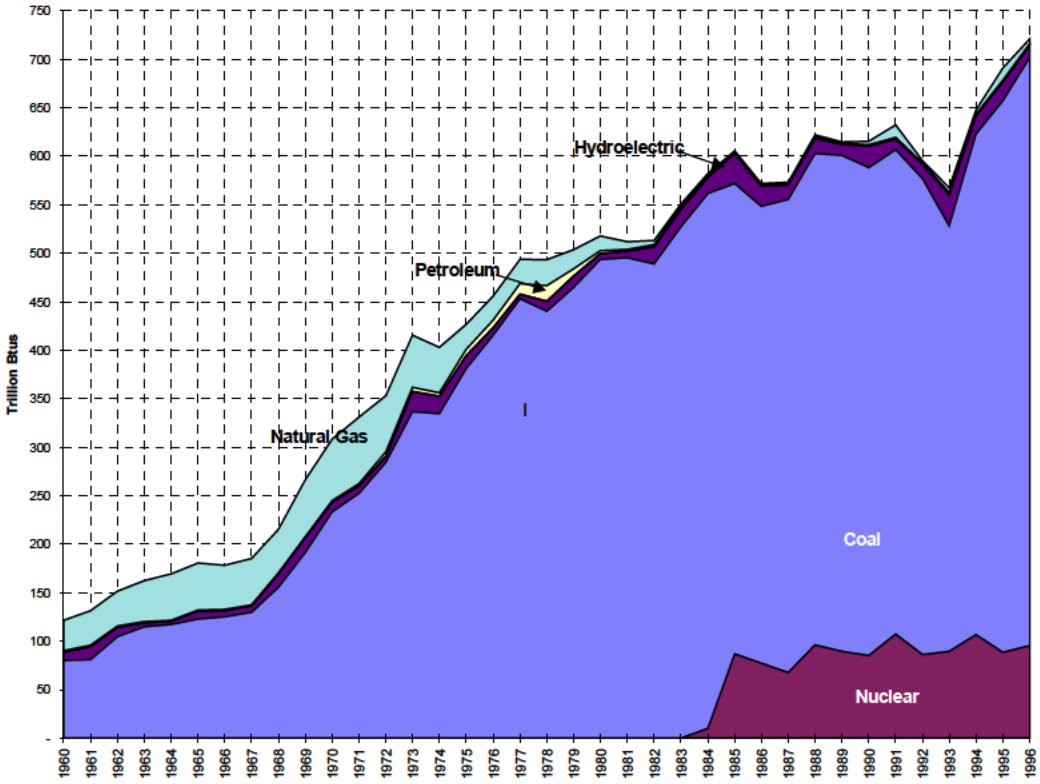
Nuclear and hydroelectric generation are also significant sources of baseload electric generation in Missouri. As Table 6 indicates, between 1990 and 1996, the share of nuclear generation fluctuated between 13 percent and 17 percent, and the share of hydroelectric generation fluctuated between 2 percent and 6 percent. Despite their importance as sources of electric generation, nuclear and hydroelectric generation receive relatively little attention in this report because, following methodology used in the *1990 Inventory,* they are assumed to result in no CO_2 emissions.[3]

Chart 2 depicts the relative role of coal, other fossil fuels, and nuclear and hydroelectric power as energy inputs for electric generation in Missouri.

[2] A baseload plant is normally operated to provide all or part of the minimum electric load of a utility system. Baseload units are generally run continuously to produce electricity at a constant rate, allowing for planned maintenance and forced outages.

[3] See Chapter 1, Section 5 of the *1990 Inventory*.

Chart 2 - Missouri utilities' consumption of energy resources to generate electricity, 1960-96



As the following tables indicate, electric generation from Missouri coal-fired utility plants increased about 18 percent between 1990 and 1996, from about 48.5 million to about 57.2 million megawatt-hours.

Table 5 - Electric power generated by Missouri utilities, by source, 1990-96

Units: 1,000 kWhs

	1990	1991	1992	1993	1994	1995	1996
Nuclear	7,998,039	9,979,371	8,083,975	8,381,333	10,006,491	8,241,833	8,890,377
Hydroelectric	2,192,175	1,119,576	1,481,265	3,184,483	1,916,316	1,918,507	1,304,084
Coal	48,501,751	47,907,503	46,829,678	41,167,635	49,207,156	54,146,815	57,192,971
Petroleum	86,606	118,645	80,522	155,493	116,430	117,717	92,062
Natural Gas	265,870	1,043,653	183,411	386,378	338,101	1,015,384	371,859
Total	***59,044,441***	***60,168,748***	***56,658,851***	***53,275,322***	***61,584,494***	***65,440,256***	***67,851,353***

Table 6 - Share by energy source of electric power generated by Missouri utilities, 1990-96

Units: 1,000 kWhs

	1990	1991	1992	1993	1994	1995	1996
Nuclear	13.5%	16.6%	14.3%	15.7%	16.2%	12.6%	13.1%
Hydroelectric	3.7%	1.9%	2.6%	6.0%	3.1%	2.9%	1.9%
Coal	82.1%	79.6%	82.7%	77.3%	79.9%	82.7%	84.3%
Petroleum	0.1%	0.2%	0.1%	0.3%	0.2%	0.2%	0.1%
Natural Gas	0.5%	1.7%	0.3%	0.7%	0.5%	1.6%	0.5%

Of the 57.2 million megawatt-hours generated from coal in 1996, investor-owned plants generated about two-thirds, cooperatively-owned plants about 26 percent and municipal plants the remaining 7 percent.

Table 7 - Electricity generated from coal-fired utility plants, by ownership class, 1990-96

Units: 1,000 kWhs

Total	**48,501,751**	**47,907,503**	**46,829,678**	**41,167,635**	**49,207,156**	**54,146,815**	**57,192,971**
Investor	34,274,766	34,413,598	33,322,418	31,059,658	35,638,142	36,194,017	38,263,463
Co-op	10,993,738	10,572,940	10,491,953	6,999,029	10,198,637	14,669,769	14,826,778
Municipal	3,233,247	2,920,965	3,015,307	3,108,948	3,370,377	3,283,029	4,102,730

Section 2: Trends in Missouri coal consumption

In 1996, Missouri utilities consumed more than 600 trillion Btus of coal, a historic high and about 20 percent more than in 1990. Utilities were the only sector where coal consumption grew during the 1990s.[4] Coal use declined by about 6 trillion Btus in the commercial, industrial and residential sectors[5] but increased by about 103 trillion Btus in the utility sector, for a net increase of about 97 trillion Btus during the period. The utility sector's share of total state coal consumption grew from about 93 percent in 1990 to 95 percent in 1996.

Table 8 - Estimated coal use in Missouri, 1990-96

Units: Trillion Btus

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**
Commercial	4.0	3.6	3.2	3.8	3.2	3.3	3.2
Industrial	30.4	28.7	26.6	27.8	24.6	25.4	25.1
Residential	2.2	1.9	1.7	2.0	1.8	1.8	1.7
Utility	502.9	499.6	490.7	438.7	516.2	568.8	606.2
Total coal use	***539.5***	***533.9***	***522.3***	***472.3***	***545.8***	***599.2***	***636.2***
Change from previous period		-1.0%	-2.2%	-9.6%	15.6%	9.8%	6.2%
Change from 1990 base year		-1.0%	-3.2%	-12.5%	1.2%	11.1%	17.9%
Share of total coal consumption:							
Commercial	0.8%	0.7%	0.6%	0.8%	0.6%	0.5%	0.5%
Industrial	5.6%	5.4%	5.1%	5.9%	4.5%	4.2%	3.9%
Residential	0.4%	0.4%	0.3%	0.4%	0.3%	0.3%	0.3%
Utility	93.2%	93.6%	93.9%	92.9%	94.6%	94.9%	95.3%

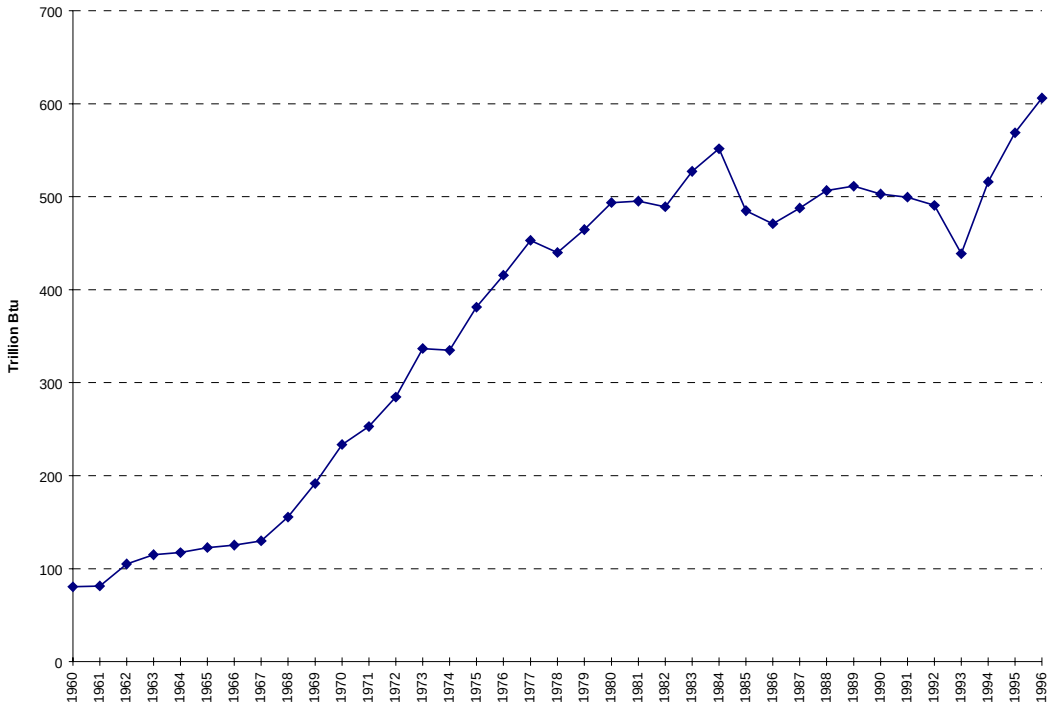
Utility coal use did not increase constantly throughout the period. It decreased by about 64 trillion Btus between 1990 and 1993, then increased by about 167 trillion Btus between 1993 and 1996.

[4] The estimates for the commercial and industrial sectors include coal use and emissions from several non-utilities such as university campuses or industrial plants that generate or co-generate electricity from coal. Because non-utilities are not required to report coal consumption to USDOE, data on their coal consumption is not readily available, and it is uncertain what portion of commercial and industrial coal use is for electric generation.

[5] Coal consumption for these three sectors in 1995 and 1996 had to be estimated; 1990 to 1994 data was taken from the EIA State Energy Data System. The coal consumption estimates for the utility sector were derived from required reports submitted by the utilities.

Chart 3 depicts the growth pattern in utility use of coal from 1990 to 1996 in the context of trends since 1960. Missouri utility coal use increased more or less steadily from 1960 through 1984, decreased from 1984 to 1986 as Union Electric's Callaway Nuclear Plant came on line, and resumed a pattern of gradual increase between 1986 and 1990 before declining from 1990 to 1993 and beginning its sharp rise in 1994.

Chart 3 - Coal burned by Missouri utilities to generate electricity, 1960-96



As Table 9 indicates, utilities in all three utility ownership categories increased their coal consumption between 1990 and 1996. Although some municipal utilities rely heavily on natural gas, the fastest growth in coal use between 1995 and 1996 occurred among municipal utilities.

Table 9 - Missouri utility consumption of fossil fuels, 1990-96

Units: Million Btus

		1990	1991	1992	1993	1994	1995	1996
Total		***507,618,786***	***513,905,198***	***494,111,874***	***445,917,459***	***522,233,151***	***583,367,648***	***608,065,356***
Investor		355,836,824	363,298,447	351,033,970	336,806,879	377,851,788	387,628,268	406,766,620
	Coal	354,202,346	359,747,840	349,631,781	331,755,926	374,625,017	378,437,732	401,938,881
	Natural Gas	819,502	2,516,395	652,232	3,216,083	1,921,081	7,781,900	3,531,345
	Petroleum	814,976	1,034,211	749,957	1,834,869	1,305,690	1,408,636	1,296,394
Co-op		112,178,635	107,279,831	107,214,424	73,539,779	104,937,525	154,656,393	153,971,702
	Coal	112,048,219	107,137,572	107,071,100	73,295,909	104,780,867	154,547,815	153,875,910
	Petroleum	130,416	142,258	143,324	243,869	156,658	108,578	95,792
Municipal		39,603,327	43,326,921	35,863,480	35,570,802	39,443,839	41,082,987	47,327,034
	Coal	36,619,786	32,717,166	33,974,081	33,661,135	36,822,403	35,829,914	45,891,399
	Natural Gas	2,761,935	10,370,335	1,718,068	1,714,454	2,429,735	5,047,718	1,379,575
	Petroleum	221,606	239,419	171,331	195,213	191,701	205,355	56,060

Section 3: Trends in CO_2 emissions from use of coal in Missouri

Trends in CO_2 emissions from utility coal combustion mirrored those in utility consumption of coal. CO_2 emissions decreased by almost 6 million tons between 1990 and 1993, then increased between 1993 and 1996 by nearly 18 million tons, for a net increase of nearly 12 million tons. CO_2 emissions from utility coal use in 1996 were about 37 percent higher than in 1993.

The increase in utility CO_2 emissions from coal combustion was partly offset by a decrease in CO_2 emissions from coal use by the commercial, industrial and residential sectors.[6] Utility CO_2 emissions from coal grew about 23 percent between 1990 and 1996, and emissions from coal use in all sectors increased by about 20 percent.

Table 10 - Estimated CO_2 emissions from coal combustion in Missouri, by sector, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996	Change from 1990 base	
Commercial	410.4	364.6	330.4	385.3	330.4	332.6	325.2	(85.2)	-20.8%
Industrial	3,099.9	2,931.8	2,724.6	2,839.0	2,512.2	2,588.8	2,564.1	(535.7)	-17.3%
Residential	221.0	196.3	177.9	208.6	178.3	180.5	173.0	(48.0)	-21.7%
Utility	51,238.0	50,997.5	50,124.0	45,284.0	53,458.3	59,362.0	62,886.8	11,648.8	22.7%
Total coal	***54,969.3***	***54,490.2***	***53,356.8***	***48,717.0***	***56,479.1***	***62,463.8***	***65,949.1***	10,979.8	20.0%
Change - prev. year		-0.9%	-2.1%	-8.7%	15.9%	10.6%	5.6%		
Change - 1990 base		-0.9%	-2.9%	-11.4%	2.7%	13.6%	20.0%		

As the following tables indicate, the trend for utility CO_2 emissions from fossil fuel combustion was influenced primarily by increases and decreases in emissions from coal. Utility emissions from fossil fuel combustion increased about 23 percent between 1990 and 1996, with emissions from coal contributing most of the increase. Throughout the period, about 99.4 percent of utility CO_2 emissions were from coal combustion. There were large temporary increases in natural gas use by some utilities in 1991 and 1995 in response to lower natural gas prices, but these increases did not change the dominance of coal combustion as an emissions source. Although CO_2 emissions from petroleum and natural gas increased between 1990 and 1996, this contributed less than 1 percent of the total increase in emissions during the period.

[6] Coal consumption for these three sectors in 1995 and 1996 had to be estimated; 1990 to 1994 data was taken from the EIA State Energy Data System. The coal consumption estimates for the utility sector were derived from required reports submitted by the utilities.

Table 11 - Estimated CO_2 emissions from Missouri utilities' use of fossil fuels to generate electricity, by fuel and ownership class, 1990-96

Units: Short Tons Carbon Dioxide (CO_2)

		1990	1991	1992	1993	1994	1995	1996
Total		***51,538,570***	***51,856,655***	***50,346,224***	***45,751,983***	***53,843,243***	***60,242,644***	***63,287,710***
Coal		51,238,014	50,997,460	50,123,968	45,284,048	53,458,252	59,361,956	62,886,778
	Investor	36,295,050	36,953,152	35,954,884	34,341,986	38,858,533	39,391,378	42,021,612
	Co-op	11,250,533	10,747,621	10,744,949	7,491,839	10,818,351	16,256,945	16,182,801
	Municipal	3,692,431	3,296,688	3,424,135	3,450,223	3,781,368	3,713,633	4,682,365
Nat. Gas		207,360	746,122	137,237	285,471	251,906	742,816	284,335
	Investor	47,448	145,696	37,763	186,206	111,228	450,560	204,460
	Municipal	159,912	600,427	99,474	99,264	140,678	292,255	79,875
Petroleum		93,196	113,073	85,020	182,464	133,086	137,872	116,598
	Investor	65,084	82,592	59,892	147,399	105,266	112,801	104,471
	Co-op	10,415	11,361	11,446	19,475	12,511	8,671	7,650
	Municipal	17,697	19,120	13,682	15,590	15,309	16,400	4,477

Table 12 - Percent change in CO_2 emissions from MO utilities' use of fossil fuels to generate electricity compared to the 1990 base year, by fuel and ownership class, 1990-96

		1990	1991	1992	1993	1994	1995	1996
Total		***0.0%***	***0.6%***	***-2.3%***	***-11.2%***	***4.5%***	***16.9%***	***22.8%***
Coal		0.0%	-0.5%	-2.2%	-11.6%	4.3%	15.9%	22.7%
	Investor	0.0%	1.8%	-0.9%	-5.4%	7.1%	8.5%	15.8%
	Co-op	0.0%	-4.5%	-4.5%	-33.4%	-3.8%	44.5%	43.8%
	Municipal	0.0%	-10.7%	-7.3%	-6.6%	2.4%	0.6%	26.8%
Nat. Gas		0.0%	259.8%	-33.8%	37.7%	21.5%	258.2%	37.1%
	Investor	0.0%	207.1%	-20.4%	292.4%	134.4%	849.6%	330.9%
	Municipal	0.0%	275.5%	-37.8%	-37.9%	-12.0%	82.8%	-50.1%
Petroleum		0.0%	21.3%	-8.8%	95.8%	42.8%	47.9%	25.1%
	Investor	0.0%	26.9%	-8.0%	126.5%	61.7%	73.3%	60.5%
	Co-op	0.0%	9.1%	9.9%	87.0%	20.1%	-16.7%	-26.5%
	Municipal	0.0%	8.0%	-22.7%	-11.9%	-13.5%	-7.3%	-74.7%

Although utility CO_2 emissions from utility coal combustion increased nearly 23 percent between 1990 and 1996, the increase occurred primarily during the final three years of the period, as Chart 4 illustrates.

Utility CO_2 emissions from coal decreased by nearly 6 million tons between 1990 and 1993. About 1 million tons of this decrease occurred between 1990 and 1992 and the remaining 5 million occurred in 1993.

In 1991, utility emissions from coal use decreased slightly despite a 4.5 percent increase in electricity sales. The decrease occurred because municipal utilities substituted natural gas for coal generation in response to low natural gas prices, and co-op utilities substituted wholesale power purchases for generation from coal.

In 1992, in response to an unusually cool summer, residential and commercial electricity sales decreased to a level slightly below 1990 sales, resulting in decreases in fossil fuel use and emissions by all three utility classes (investor, co-op and municipal). Utility CO_2 emissions in 1992 were about 2 percent below 1990 levels.

In 1993, with the return of normal summer weather, electricity sales to residential and commercial customers rebounded. Total electricity sales in 1993 were about 8.4 percent higher than in 1990. Nevertheless, utility coal use and CO_2 emissions decreased to about 88 percent of the 1990 level due to several factors, including flooding that cut off Eastern coal supplies and other transportation routes for coal, a labor strike in Eastern coal mining states that also decreased the supply of coal, increased availability of inexpensive hydroelectric power and relatively low prices for natural gas.

From 1993 through 1996, following this 3-year decline in CO_2 emissions from utility coal use, generation from coal steadily increased. Utility coal use in 1996 was 20 percent higher than in 1990 and 37 percent higher than in 1993. The increase came as utilities, responding to growing electricity demand and the decreasing price of coal, took advantage of the existing excess coal generating capacity in Missouri.

Electricity sales in 1996 were about 20 percent higher than in 1990; compared to the previous year, electricity sales increased by about 1.8 percent in 1994, 4.3 percent in 1995 and 4.2 percent in 1996.[7] Residential and commercial electricity sales during this period increased in response to population and economic growth in the state. Industrial electricity sales increased due to these factors as well as steadily decreasing electricity rates for industry.[8]

On the supply side, the average delivered cost of coal to Missouri utilities decreased rapidly after 1992, as Missouri utilities switched from coal mined in Missouri and imported from Eastern states to coal imported from Wyoming and other western states. The average delivered price of coal to utilities decreased about 7 percent in 1993, 11 percent in 1994, 11 percent in 1995 and 3 percent in 1996. The average delivered price in 1996, 95.5 cents per million Btu, was nearly 30 percent lower than in 1992, 133.6 cents per million Btu.[9]

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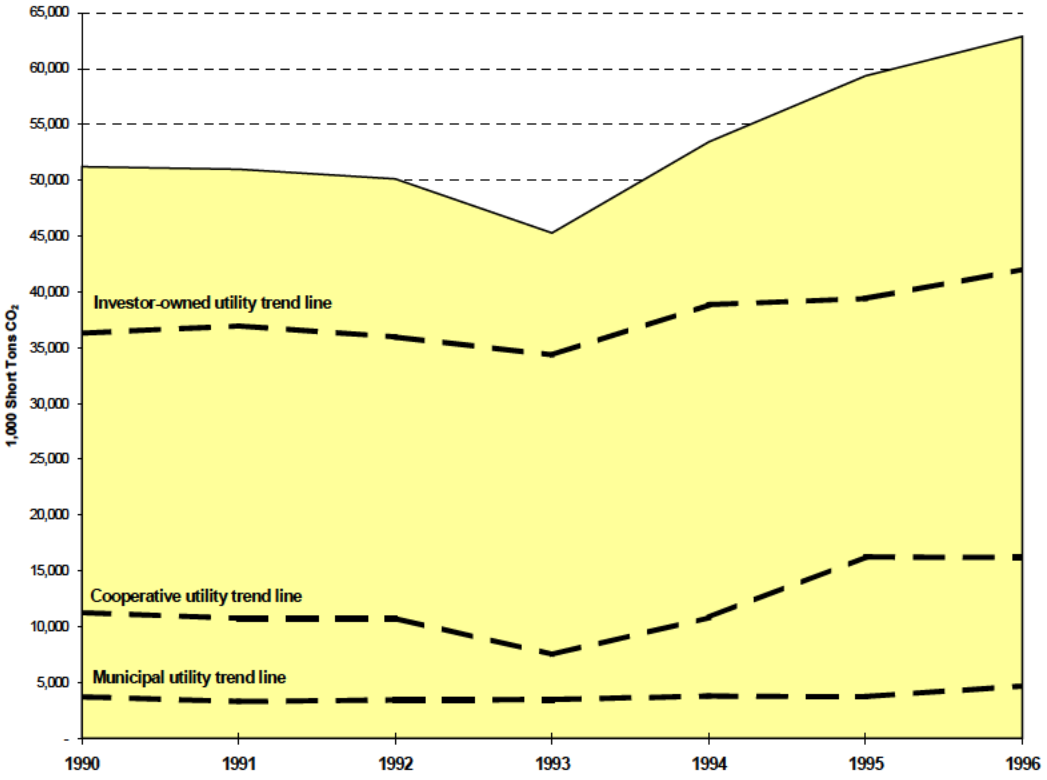
[7] Due to variations in the weather, the growth of electricity sales in Missouri slowed too only about 0.5 percent in 1997 but increased to about 7.8 percent during the first half of 1998.

[8] During the 20 years prior to 1990, the average price for electricity delivered to Missouri industry increased every year except 1984. Since 1990, the average price to industry has decreased every year. The average price in nominal dollars for electricity delivered to Missouri industry decreased about 8.3 percent between 1990 and 1995, from $14.50 per million Btu in 1990 to $13.29 in 1995. The average price to residential and commercial customers also decreased between 1990 and 1995, but the decrease was smaller (4.1 percent to commercial customers and 1.4 percent to residential customers) and price changes followed a mixed pattern of price increases and decreases from year to year. USDOE/EIA, *State Energy Price and Expenditure Report*, 1995.

[9] USDOE/EIA, *Cost and Quality of Fuels for Electric Utility Plants*, 1992 and 1996, Table 2.

The steady increase in utility generation from coal between 1993 and 1996 led to a rapid increase in CO_2 emissions. CO_2 emissions from utility coal use increased by more than 18 million tons between 1994 and 1996. The level of utility CO_2 emissions from coal in 1996, 62.9 million tons, was about 23 percent higher than in 1990 and 39 percent higher than in 1993.

Chart 4 - CO_2 emissions from Missouri utilities' use of coal to generate electricity, by ownership class, 1990-96



CO_2 emissions trends varied among investor-owned, cooperatively owned and municipal utilities. CO_2 emissions from investor-owned, coal-fired plants increased about 5.7 million tons (about 16 percent) between 1990 and 1996. However, on a percentage growth basis, there were larger increases in CO_2 emissions in cooperative and municipal coal-fired plants — a 44 percent increase for cooperatives and a 27 percent increase for municipals. Accordingly, investor-owned utilities' share of total coal-fired CO_2 emissions fell between 1990 to 1996, from 70 percent in 1990 to 66 percent in 1996. Table 13 summarizes the relative role of investor-owned, cooperative and municipal utilities as sources of CO_2 emissions between 1990 and 1996

Table 13 - Estimated CO_2 emissions from Missouri utilities' use of fossil fuels to generate electricity, by ownership class and fuel, 1990-96

Units: Short Tons Carbon Dioxide (CO_2)

		1990	1991	1992	1993	1994	1995	1996
Total		***51,538,570***	***51,856,655***	***50,346,224***	***45,751,983***	***53,843,243***	***60,242,644***	***63,287,710***
Investor		36,407,582	37,181,439	36,052,539	34,675,592	39,075,027	39,954,739	42,330,542
	Coal	36,295,050	36,953,152	35,954,884	34,341,986	38,858,533	39,391,378	42,021,612
	Natural Gas	47,448	145,696	37,763	186,206	111,228	450,560	204,460
	Petroleum	65,084	82,592	59,892	147,399	105,266	112,801	104,471
Coop		11,260,948	10,758,981	10,756,395	7,511,314	10,830,861	16,265,616	16,190,451
	Coal	11,250,533	10,747,621	10,744,949	7,491,839	10,818,351	16,256,945	16,182,801
	Petroleum	10,415	11,361	11,446	19,475	12,511	8,671	7,650
Municipal		3,870,040	3,916,235	3,537,291	3,565,077	3,937,355	4,022,288	4,766,718
	Coal	3,692,431	3,296,688	3,424,135	3,450,223	3,781,368	3,713,633	4,682,365
	Natural Gas	159,912	600,427	99,474	99,264	140,678	292,255	79,875
	Petroleum	17,697	19,120	13,682	15,590	15,309	16,400	4,477

CO_2 emissions trends also varied for the 21 different utility plants burning coal in Missouri. Table 14 lists plants in descending order based on CO_2 emissions levels in 1996.

Table 14 - Estimated CO_2 emissions from coal burned to generate electricity, by utility plant, 1990-96

Units: Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996	1990-96
UE - Labadie	11,673,913	11,294,043	11,734,823	10,288,919	12,419,696	13,785,217	13,357,925	14.4%
AEC - Thomas Hill	4,285,879	3,876,425	4,245,410	1,447,144	4,278,811	8,089,601	8,284,256	93.3%
AEC - New Madrid	6,660,830	6,636,641	6,315,138	5,794,581	6,169,648	7,920,858	7,480,771	12.3%
UE - Rush Island	5,527,194	5,804,567	5,177,976	5,119,321	6,103,978	6,305,635	7,333,896	32.7%
KCPL - Iatan	4,503,759	4,653,070	4,359,896	3,890,295	5,119,203	4,900,284	5,150,289	14.4%
UE - Sioux	4,393,579	4,300,082	3,721,272	3,545,205	3,076,942	3,649,300	4,285,061	-2.5%
Utilicorp - Sibley	1,770,180	2,198,368	2,367,636	2,132,456	2,866,505	2,789,146	3,001,152	69.5%
KCPL - Montrose	2,476,327	2,445,530	2,595,719	3,082,051	3,069,836	2,843,901	2,893,500	16.8%
KCPL - Hawthorn	2,413,820	2,704,536	2,319,878	2,246,180	2,541,467	2,067,642	2,647,784	9.7%
Sikeston	1,466,101	1,678,826	1,238,018	1,360,613	1,555,781	1,602,408	1,756,911	19.8%
UE - Meramac	1,790,251	1,942,061	1,776,193	2,044,024	1,785,329	1,268,922	1,747,552	-2.4%
Springfield - James River	880,627	228,786	792,173	765,398	862,036	1,055,455	1,448,710	64.5%
Empire - Asbury	1,471,915	1,357,492	1,669,525	1,667,648	1,611,778	1,598,023	1,268,717	-13.8%
Springfield - Southwest	1,035,048	1,102,715	1,130,582	993,645	1,021,741	780,379	1,162,080	12.3%
Central EC - Chamois	303,825	234,554	184,401	250,114	369,891	246,486	417,773	37.5%
St. Joseph - Lake Road	274,113	253,402	231,965	325,888	263,799	183,309	335,736	22.5%
Independence - Blue Valley	106,539	95,739	88,910	133,862	127,756	93,803	123,535	16.0%
Columbia	78,335	143,879	112,024	108,489	128,870	96,902	113,286	44.6%
Marshall	93,820	18,960	34,000	59,492	44,840	57,568	61,152	-34.8%
Chillicothe - Beardmore	31,855	27,782	25,765	28,723	40,344	27,117	15,447	-51.5%
Independence - Missouri	106	-	2,661	-	-	-	1,244	
	51,238,014	50,997,460	50,123,968	45,284,048	53,458,252	59,361,956	62,886,778	22.7%

CO_2 emissions from coal use at some plants increased sufficiently to move them higher in the rankings on Table 14. For example, CO_2 emissions from Associated Electric Cooperative's (AEC) Thomas Hill plant were about 93 percent higher in 1996 than 1990, with most of the increase coming in 1994 and 1995. CO_2 emissions from coal combustion at Springfield's James River municipal power plant increased about 65 percent between 1990 and 1996, with most of the increase occurring in 1994 through 1996.[10]

The largest percentage increases in CO_2 emissions among the investor-owned plants occurred at Utilicorp's Sibley plant and Union Electric's Rush Island plant where emissions increased about 70 percent and 33 percent respectively. More than half of the increase at the Rush Island plant occurred during 1995 and 1996.

Despite changes within the rankings of different plants, the top-heavy distribution of CO_2 emissions in 1996 was nearly identical to that in 1990, with the seven leading plants producing about 76 to 77 percent of the CO_2 emissions, the middle third producing about 22 to 23 percent, and the final third producing only about 1 percent.

[10] It should not be inferred that overall emissions from the Springfield utility increased by this amount. Boilers operated by Springfield Municipal Utility in its James River plant can burn either coal or natural gas. The James River Plant's CO_2 emissions from coal combustion were unusually high in 1996 because the utility substituted coal for natural gas during that year in response to high natural gas prices. In 1995, the James River Plant burned only about a third as much natural gas as in 1990 and about 60 percent as much natural gas as in 1995. Springfield Municipal Utility's CO_2 emissions from all fossil fuel combustion grew by about 30 percent between 1990 and 1996, a substantial increase but much less than 65 percent.

Section 4: Trends in the source and carbon content of coal consumed by Missouri utilities

Between 1990 and 1996, there was a shift in the source of Missouri utility coal purchases, which resulted in an increase in the average carbon content of coal burned in Missouri coal-fired plants. Utility emissions from coal use would have been about 1.6 million tons lower in 1996 if Missouri utilities had burned the same quantity of coal using the same sources that they were using in 1990.

Coal has the highest carbon content of commonly used fossil fuels, although coal from different states varies in its carbon content. On the average, natural gas contains about 55 percent of the carbon contained in coal. Petroleum carbon content varies widely by product but generally falls between that of coal and natural gas.

Shifts between different fossil fuels can affect the level of CO_2 emissions independently of the level of total energy use. An example for Missouri occurred in 1992 and 1993, when the state's net energy consumption increased by about 10 trillion Btus while CO_2 emissions from energy use decreased. Increases in total state consumption of natural gas and petroleum more than offset reductions in coal consumption, but the reduction in coal use weighed more heavily on net CO_2 emissions because of coal's high carbon content.

Shifts between different coal sources can also affect the level of CO_2 emissions independently of the level of total energy use, and this occurred in Missouri during 1990 through 1996. During this period, as indicated by Chart 5, Missouri utilities largely shifted from burning coal mined in Eastern states such as Missouri and Illinois to coal mined in Western states, especially Wyoming.[11] Receipts of Wyoming coal nearly quadrupled from 7.6 million short tons, 31 percent of total receipts in 1990, to 26.8 million short tons, 87 percent of total receipts in 1996.

The shift took place because Western coal was priced lower and contained less sulfur than eastern coal. However, because the average carbon content per Btu of Western coal exceeds that for eastern coal, the shift of coal source also contributed to higher CO_2 emissions than would otherwise have occurred.[12] Chart 6 illustrates the increase in average carbon content of utility coal that took place from 1990 to 1996.

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[11] Receipts data is from the 1990 to 1996 editions of the annual USDOE/ EIA, series *Cost and Quality of Fuels for Electric Utility Plants*, Tables 24 and 36.

[12] For example, Wyoming coal contains about 58.01 pounds of carbon per MBtus compared to 55.5 for Illinois coal and 54.9 for Missouri coal. Estimates of carbon content are from Hong, B.D. and E.R. Slatick, Carbon Dioxide Emissions Factors for Coal, USDOE/EIA, *Quarterly Coal Report, January-March 1994*, pp. 1-8.

Chart 5 - Missouri utilities' shift from Eastern coal to Western coal, 1990-96

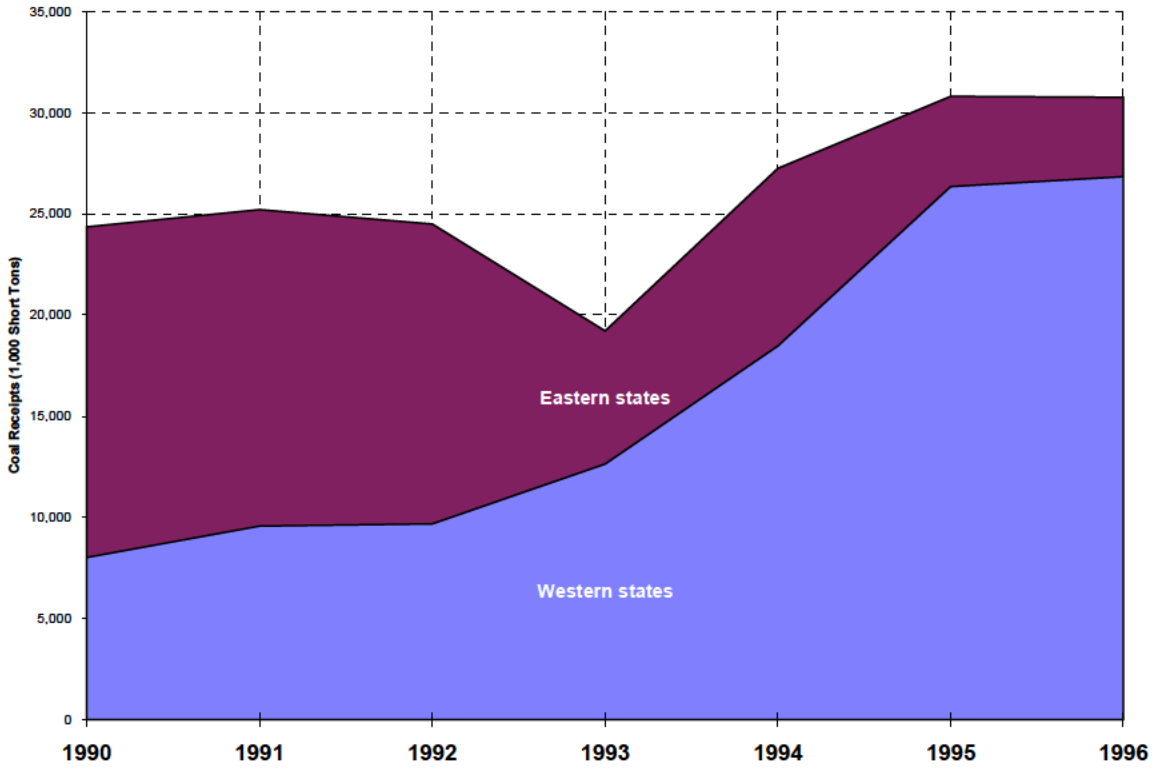
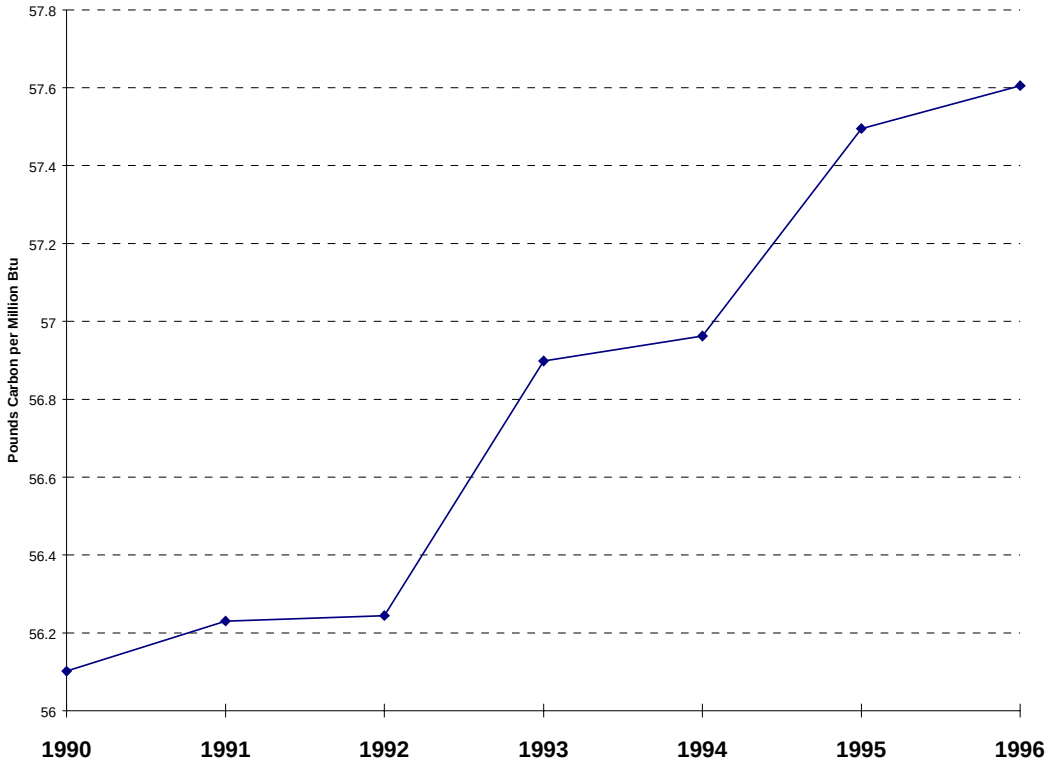


Chart 6 - Estimated increase in average carbon content of coal received by Missouri utilities, 1990-96



Part 3: Trends in combustion of petroleum and associated CO_2 emissions

Section 1: Petroleum consumption

As Table 15 indicates, the transportation sector consumed about 86 percent of petroleum in Missouri during the period from 1990 to 1996. Petroleum use grew in every sector during the period, but most of the growth and the most dramatic shifts occurred in the transportation sector.

Gasoline, primarily used in personal vehicles, accounts for more than half of the petroleum used for energy in the state. However, its share fell from about 61 percent of petroleum energy in 1990 to about 56 percent in 1996.[13] The share lost by gasoline went to jet fuel (a 3.7 percent increase) and diesel fuel (a 1.5 percent increase), used primarily for commercial transportation.

Consumption of the "other" transportation petroleum products included in Table 15 — aviation gasoline, residual fuel and LPG — remained small during the period.

[13] Gasoline consumption is defined in the USDOE/EIA State Energy Data System (SEDS) as the sum of highway and marine gasoline use. The estimate for this study is the sum of the SEDS estimate of marine gasoline use and the Missouri Department of Transportation's (MoDOT) estimate of highway gasoline use. USDOE/EIA State Energy Data System data indicates that gasoline use increased between 1990 and 1991, but MoDOT data indicates that gasoline use decreased between 1990 and 1991. The reason for the discrepancy is not known.

Table 15 - Estimated use of petroleum products for energy in Missouri, 1990-96

Units: Trillion Btus

	1990	1991	1992	1993	1994	1995	1996
Transportation	466.2	466.4	481.5	497.8	522.9	537.2	560.8
Gasoline	332.4	332.2	336.0	340.5	349.1	352.2	360.9
Diesel	94.9	90.7	101.8	105.2	112.2	118.0	126.9
Jet fuel	37.6	42.5	42.6	51.2	60.2	65.9	71.8
Other	1.3	1.1	1.0	1.0	1.4	1.1	1.1
Commercial	9.5	10.9	11.1	11.1	11.4	11.5	11.6
Industrial	48.9	40.2	43.6	49.2	50.8	50.1	51.3
Residential	17.4	22.6	22.3	23.8	23.2	23.4	24.4
Utility	1.2	1.4	1.1	2.3	1.7	1.7	1.4
Total petroleum use	***543.2***	***541.5***	***559.6***	***584.2***	***610.0***	***624.0***	***649.5***
Change from previous period		-0.3%	3.3%	4.4%	4.4%	2.3%	4.1%
Change from 1990 base year		-0.3%	3.0%	7.5%	12.3%	14.9%	19.6%
Share of total petroleum consumption:							
Transportation	85.8%	86.1%	86.0%	85.2%	85.7%	86.1%	86.3%
Gasoline	61.2%	61.3%	60.0%	58.3%	57.2%	56.4%	55.6%
Diesel	17.5%	16.8%	18.2%	18.0%	18.4%	18.9%	19.5%
Jet fuel	6.9%	7.8%	7.6%	8.8%	9.9%	10.6%	11.1%
Other	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Commercial	1.7%	2.0%	2.0%	1.9%	1.9%	1.8%	1.8%
Industrial	9.0%	7.4%	7.8%	8.4%	8.3%	8.0%	7.9%
Residential	3.2%	4.2%	4.0%	4.1%	3.8%	3.8%	3.8%
Utility	0.2%	0.3%	0.2%	0.4%	0.3%	0.3%	0.2%

Breakdown of transportation “other petroleum” consumption

Units: Trillion Btus

Other petroleum	96	77	75	76	105	84	81
Aviation gasoline	48	45	44	36	43	44	42
Residual fuel	19	0	9	18	12	10	8
LPG	29	32	22	22	50	31	30

After transportation, industry was the second most important consumer of petroleum. Petroleum products used by Missouri industry for their heat content include distillate and residual fuel, kerosene, LPG, gasoline, and some of the products classified jointly by EIA as “other petroleum.” The particular “other petroleum” products used for energy in Missouri are pentanes plus, petroleum coke and a portion of “miscellaneous” petroleum products.

Table 16 - Estimated Missouri industry use of petroleum products for energy, 1990-96

Units: Trillion Btus

	1990	1991	1992	1993	1994	1995	1996
Distillate	17.5	17.2	19.0	16.3	20.3	20.1	20.3
Kerosene	0.0	0.1	0.0	0.0	0.1	0.1	0.1
LPG (Energy)	6.5	7.3	6.6	9.2	9.1	8.8	9.9
Gasoline	3.5	4.0	3.5	7.7	8.5	8.5	8.5
Residual	3.3	3.0	3.9	6.4	2.9	2.9	2.0
Other Petroleum	18.1	8.7	10.6	9.5	9.9	9.8	10.4
	48.9	40.2	43.6	49.2	50.8	50.1	51.3

The decline in use of "other" petroleum products between 1990-91 is an artifact of a USDOE/EIA "re-estimate" of consumption for this series in the SEDS database.[14]

A portion of industry LPG use (1.7 percent) and petroleum coke use (25 percent) is devoted to non-energy purposes. This and other instances of industry non-energy petroleum consumption do not appear in Table 16. They are included in a section of Chapter 4 discussing CO_2 emissions from non-energy uses of fossil fuels.

Among electric utilities, petroleum consumption was fairly constant over the period from 1990 to 1996, peaking in 1993 when investor-owned consumption was about 50 percent higher than average. However, use of petroleum increased among investor-owned utilities and decreased among the other two sectors.

Section 2: CO_2 emissions from petroleum

The transportation sector was the largest source of CO_2 emissions from petroleum from 1990 to 1996, and CO_2 emissions from the sector grew about 19 percent during the period. About 92 percent of this growth was due to increased emissions from gasoline, diesel and jet fuel used for transportation. CO_2 emissions from jet fuel grew an estimated 2.7 million tons, followed by diesel (2.6 million tons) and motor gasoline (2.2 million tons).

[14] USDOE/EIA, State Energy Data Report 1994, Appendix G, p. 527.

Table 17 - Estimated CO_2 emissions from petroleum combustion in Missouri, by sector, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996	Change from 1990 base	
Transportation:	36,470.5	36,485.7	37,677.9	38,966.8	40,941.1	42,075.2	43,929.6	7,459.1	20.5%
Gasoline	25,826.2	25,810.1	26,109.2	26,454.2	27,125.4	27,364.2	28,044.0	2,217.8	8.6%
Diesel	7,577.5	7,245.5	8,131.8	8,396.6	8,958.5	9,423.1	10,131.3	2,553.7	33.7%
Jet fuel	2,970.7	3,353.3	3,361.9	4,039.5	4,752.0	5,204.0	5,672.1	2,701.5	90.9%
Other	96.1	76.8	75.0	76.4	105.1	83.9	82.2	(13.9)	-14.5%
Commercial	720.7	823.4	844.4	844.2	864.6	870.6	881.3	160.6	22.3%
Industrial	4,106.9	3,262.6	3,579.6	3,984.7	4,100.8	4,043.6	4,127.3	20.3	0.5%
Residential	1,199.5	1,552.0	1,534.4	1,635.5	1,594.6	1,611.6	1,679.6	480.0	40.0%
Utility	93.2	113.1	85.0	182.5	133.1	137.9	116.6	23.4	25.1%
Total petroleum	***42,590.9***	***42,236.7***	***43,721.4***	***45,613.7***	***47,634.2***	***48,738.9***	***50,734.3***	8,143.4	19.1%
Change - prev. year		-0.8%	3.5%	4.3%	4.4%	2.3%	4.1%		

As Table 17 indicates, the growth in CO_2 emissions from combustion of petroleum, while not steady, was more even from 1990 to 1996 than the growth in CO_2 emissions from combustion of coal. Industrial emissions from petroleum use are summarized in Table 18.

Table 18 - Estimated CO_2 emissions from industrial petroleum combustion in Missouri, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996
Distillate	1,399	1,371	1,515	1,304	1,620	1,607	1,619
Kerosene	3	10	3	2	5	5	5
LPG (Energy)	445	499	454	632	624	604	682
Gasoline	269	309	273	599	663	660	663
Residual	285	258	336	549	252	247	175
Other Petroleum	1,705	816	998	899	938	920	983
	4,107	3,263	3,580	3,985	4,101	4,044	4,127

During 1993, the year of their peak petroleum consumption, Missouri utilities generated about 0.1 million megawatt-hours of electricity from petroleum, about 0.4 percent of that generated from coal. The resulting CO_2 emissions were only about 0.3 percent of those from coal; petroleum contains less carbon per Btus than coal.

Part 4: Trends in combustion of natural gas and resulting CO_2 emissions

As Table 19 indicates, 95 percent of Missouri's use of natural gas for energy occurs in the residential, commercial and industrial sectors.

A small portion (4.1 percent) of total natural gas consumption by industry is for non-energy purposes. Industry consumption of natural gas for non-energy purposes does not appear in the table, but is included in Chapter 4's discussion of CO_2 emissions from non-energy uses of fossil fuels.

Table 19 - Estimated combustion of natural gas in Missouri's end-use sectors, 1990-96

Units: Trillion Btus

	1990	1991	1992	1993	1994	1995	1996
Transportation	5.4	2.6	2.3	9.9	2.9	4.7	4.8
Commercial	60.0	63.7	61.1	69.9	66.6	65.1	73.2
Industrial	52.9	55.3	56.2	58.7	69.1	66.4	67.4
Residential	117.2	121.7	116.9	134.7	123.3	125.1	137.2
Utility	3.6	12.9	2.4	4.9	4.4	12.8	4.9
Total natural gas use	***239.1***	***256.3***	***238.8***	***278.2***	***266.2***	***274.2***	***287.4***
Change from previous period		7.2%	-6.8%	16.5%	-4.3%	3.0%	4.8%
Change from 1990 base year		7.2%	-0.1%	16.4%	11.4%	14.7%	20.2%
Share of total natural gas consumption:							
Transportation	2.2%	1.0%	1.0%	3.6%	1.1%	1.7%	1.7%
Commercial	25.1%	24.9%	25.6%	25.1%	25.0%	23.7%	25.5%
Industrial	22.1%	21.6%	23.5%	21.1%	25.9%	24.2%	23.4%
Residential	49.0%	47.5%	48.9%	48.4%	46.3%	45.6%	47.7%
Utility	1.5%	5.0%	1.0%	1.8%	1.6%	4.7%	1.7%

Unlike utility petroleum consumption, utility natural gas consumption was volatile over the period between 1990 and 1996, peaking at 12.9 trillion Btus in 1991, dropping to 2.4 trillion Btus in 1992, and continuing to vary during the following years. The volatility of natural gas consumption reflected both year-to-year changes in peaking requirements and the volatility of natural gas prices.[15]

The average price of natural gas to utilities rose from $1.51 per 1,000 cubic feet in 1991 to $1.89 in 1992, peaked at $2.34 in 1993, then dropped again to $1.69 in 1995.

As Table 20 indicates, increases in CO_2 emissions from combustion of natural gas occurred primarily in the residential, commercial and industrial sectors. Emissions increased about 27 percent in the industrial sector, 22 percent in the commercial sector and 17 percent in the residential sector. However, the pattern of growth was not consistent; consumption and emissions fell and rose with the rise and fall of natural gas prices.

[15] A mild summer in 1992 reduced peaking requirements in that year. Utility natural gas consumption in 1993 was buoyed by a large increase in natural gas-fired generation at the Union Electric Meramec plant during the summer of 1993.

Table 20 - Estimated CO_2 emissions from natural gas combustion in Missouri's end-use sectors, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996
Transportation	311.9	150.4	134.6	575.2	168.6	276.3	279.5
Commercial	3,494.0	3,709.9	3,554.9	4,070.7	3,876.1	3,788.0	4,258.1
Industrial	3,077.1	3,219.7	3,269.6	3,417.0	4,020.8	3,864.9	3,921.0
Residential	6,821.8	7,085.0	6,802.5	7,839.5	7,176.9	7,281.4	7,985.9
Utility	207.4	746.1	137.2	285.5	251.9	742.8	284.3
Total natural gas us	***13,912.1***	***14,911.1***	***13,898.9***	***16,187.9***	***15,494.2***	***15,953.4***	***16,728.8***
Change from previous period		7.2%	-6.8%	16.5%	-4.3%	3.0%	4.9%
Change from 1990 base year		7.2%	-0.1%	16.4%	11.4%	14.7%	20.2%
Share of total natural gas consumption:							
Transportation	2.2%	1.0%	1.0%	3.6%	1.1%	1.7%	1.7%
Commercial	25.1%	24.9%	25.6%	25.1%	25.0%	23.7%	25.5%
Industrial	22.1%	21.6%	23.5%	21.1%	26.0%	24.2%	23.4%
Residential	49.0%	47.5%	48.9%	48.4%	46.3%	45.6%	47.7%
Utility	1.5%	5.0%	1.0%	1.8%	1.6%	4.7%	1.7%

During 1991, the year of their peak natural gas consumption, Missouri utilities generated about 1 million megawatt-hours of electricity from natural gas, about 2 percent of that generated from coal. The resulting CO_2 emissions were only about 1.5 percent of those from coal.

Part 5: Allocation of Missouri utility CO_2 emissions to end users of electricity

To this point, the analytic framework for discussing sectoral energy use and CO_2 emissions has been based on primary energy use in five sectors — transportation, commercial, industrial, residential and electric utilities. An alternative analytic framework used in this chapter is based on four energy end-use sectors, excluding utilities. Table 21 summarizes the difference between the two frameworks.

Table 21 - Comparison of primary-use and end-use sectors

	Primary energy use sectors	Energy end-use sectors
Sectors included	5 sectors, including utilities	4 sectors, excluding utilities
Method used to account for CO_2 emissions from fossil fuel combustion by utilities	Included under utility sector	Allocated to end-use sectors based on their consumption of electricity
Purposes for which the framework is useful	To estimate total consumption of fossil fuels and total CO_2 emissions from their use	To analyze consumption decisions by electricity end users

Table 22 shows the allocation of utility CO_2 emissions to Missouri's electricity end-use sectors based on their consumption of electricity from 1990 to 1996. Allocated emissions increased 31 percent in the commercial sector, 23 percent in the residential sector and 10 percent in the industrial sector.

Table 22 - Allocation of estimated electric utility CO_2 emissions to Missouri's end-use sectors, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996	Change 1990-96
Utility emissions to allocate	51,539	51,857	50,346	45,752	53,852	60,246	63,288	23%
Commercial	18,479	18,365	18,207	16,251	19,415	21,777	22,986	24%
Industrial	12,365	12,033	12,436	10,628	12,726	13,865	14,372	16%
Residential	20,694	21,459	19,703	18,873	21,703	24,600	25,930	25%
Transportation	0	0	0	0	8	3	3	

Table 23 indicates total CO_2 emissions from the end-use sectors after utility emissions are allocated to the four energy end-use sectors. The allocation increases the prominence of the residential and commercial sectors relative to the industrial sector, and the prominence of all three relative to the transportation sector as a source of CO_2 emissions. Table 23 depicts emissions estimates by end-use sector.

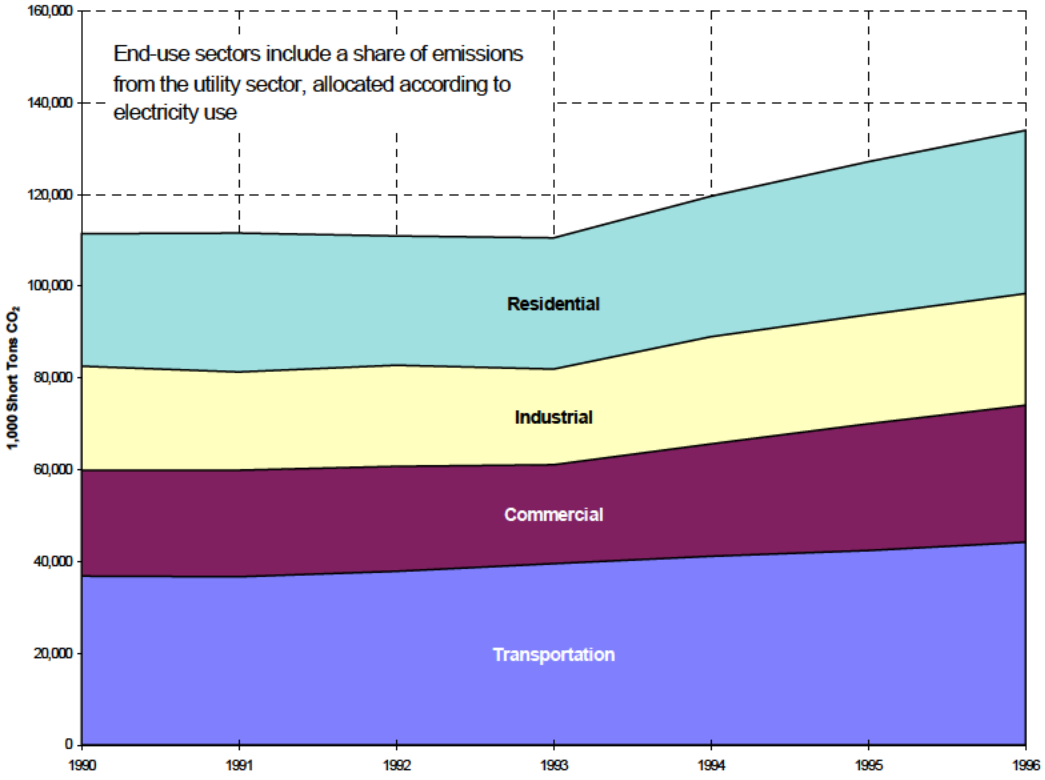
Table 23 - Estimated aggregate CO_2 emissions from electricity use and direct combustion of fossil fuels by Missouri's end-use sectors, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996
Energy end-use sectors	111,472	111,638	110,977	110,519	119,616	127,159	133,413
Transportation	36,782	36,636	37,813	39,542	41,118	42,354	44,210
Gasoline	25,826	25,810	26,109	26,454	27,125	27,364	28,044
Diesel	7,578	7,245	8,132	8,397	8,959	9,423	10,131
Jet fuel	2,971	3,353	3,362	4,040	4,752	5,204	5,672
Other	408	227	210	652	274	360	359
Transportation	0	0	0	0	8	3	3
Commercial	23,104	23,262	22,937	21,551	24,486	26,768	28,450
Electricity	18,479	18,365	18,207	16,251	19,415	21,777	22,986
Natural gas	3,494	3,710	3,555	4,071	3,876	3,788	4,258
Petroleum	721	823	844	844	865	871	881
Coal	410	365	330	385	330	333	325
Industrial	22,649	21,447	22,010	20,869	23,359	24,362	24,985
Electricity	12,365	12,033	12,436	10,628	12,726	13,865	14,372
Natural gas	3,077	3,220	3,270	3,417	4,021	3,865	3,921
Petroleum	4,107	3,263	3,580	3,985	4,101	4,044	4,127
Coal	3,100	2,932	2,725	2,839	2,512	2,589	2,564
Residential	28,937	30,292	28,218	28,557	30,653	33,674	35,768
Electricity	20,694	21,459	19,703	18,873	21,703	24,600	25,930
Natural gas	6,822	7,085	6,802	7,839	7,177	7,281	7,986
Petroleum	1,200	1,552	1,534	1,636	1,595	1,612	1,680
Coal	221	196	178	209	178	180	173

Chart 7 summarizes energy end-use sector contributions to CO_2 emissions in Missouri between 1990 and 1996. As the contrast between this chart and Chart 1 indicates, an end-use sector framework emphasizes the prominence of the residential, commercial and industrial sectors as CO_2 emissions sources relative to the transportation sector. This contrast is because nearly all electricity generated by utilities is consumed in these three sectors.

Chart 7 - Missouri end-use sector shares of CO_2 emissions from fossil fuel combustion, 1990-96



Part 6: Methods used to estimate CO_2 emissions from fossil fuel combustion

The estimation of CO_2 emissions summarized in this chapter closely followed the methodological procedures described in the *1990 Inventory*. The estimation of CO_2 emissions from fossil fuel combustion requires estimating the physical quantity (tons, barrels, cubic feet, etc.) of the fuel burned, its heat content (Btus) and its carbon content. For fossil fuel usage and quality data, the *1990 Inventory* and this report rely primarily on federal data sources compiled from reports by Missouri state agencies (such as the Missouri Department of Revenue or Missouri Department of Transportation) or producers and consumers of fossil fuels (such as refiners and electric utilities). Most heat and carbon coefficients came from the U.S. Department of Energy's Information Administration (EIA) or from USEPA. Because of the prominence of coal combustion by electric utilities as a source of CO_2 emissions in Missouri, individual heat content coefficients and carbon coefficients were estimated for each coal-fired utility plant in the state using data provided by EIA.

Table 24 summarizes the data and methods used to estimate fossil fuel combustion and CO_2 emissions.

Table 24 - Data and methods used to estimate fossil fuel combustion and CO_2 emissions

	Source	Methodological notes
Estimates of fossil fuel consumption (physical units of measure) by electric utilities for 1990-96	Electronic database supplied by EIA containing data reported by utilities using Form EIA759	The estimate is based on fossil fuel used to generate electricity at utility plants located in Missouri. Non-utility use of fossil fuels to generate electricity is included in primary fossil fuel use by the commercial and industrial sectors.
Estimates of fossil fuel consumption (Btus) by utilities prior to 1990	State Energy Data System (SEDS) electronic data supplied by EIA	
Estimates of coal consumption in other sectors	State Energy Data System (SEDS) electronic data supplied by EIA	Estimates for 1995 and 1996 are based on AEO projections.
Estimates of natural gas consumption in other sectors	State Energy Data System (SEDS) electronic data supplied by EIA; EIA, Natural Gas Annual 1995, Table 73; EIA, State Energy Data Report 1994, Appendix D	(1) EIA SEDS provided consumption of natural gas (Btus) for the years 1960 to 1994. EIA, Natural Gas Annual provided consumption of natural gas (physical units of measure) for 1995 and 1996, which was converted to Btus using thermal conversion factors from EIA, State Energy Data Report 1994, Appendix D. (2) SEDS data for industrial natural gas use includes some consumption for non-energy purposes. Non-energy use results in some sequestration of carbon, which otherwise would be released if the natural gas had been burned for energy. This study assumes the percentage of natural gas consumed for non-energy uses from 1991 to 1996 equaled the percentage (4.1%) in the 1990 baseline year. The estimate of CO_2 emissions from non-energy use of natural gas is documented in Chapter 4, Section 1 of this study.

	Source	Methodological notes
Estimates of motor gasoline consumption by the transportation sector	Data supplied by EIA and Missouri Department of Transportation (MoDOT)	EIA's SEDS classification for transportation motor gasoline includes highway and marine use. For highway consumption, SEDS data was used for 1960 to 1965 and MoDOT data for 1965 to 1996. (Annual FHWA Highway Statistics is derived from MoDOT data.) EIA supplied unpublished SEDS electronic data estimating marine consumption.
Estimates of other petroleum consumption by the transportation sector	State Energy Data System (SEDS) electronic data supplied by EIA, Fuel Oil and Kerosene Sales, Table 16	EIA's SEDS provided data for 1960 to 1994. Unpublished prime supplier sales data supplied by EIA was used to estimate 1995 and 1996 growth rates of jet and diesel fuel; these were applied to the SEDS data for 1994 consumption.
Estimates of petroleum consumption in other sectors	State Energy Data System (SEDS) electronic data supplied by EIA	(1) SEDS data for industrial petroleum consumption between 1990 and 1991 is discontinuous due to revisions described in EIA, State Energy Data Report 1994, Appendix G, pg. 527. The apparent reduction in industrial CO_2 emissions from petroleum use between 1990 and 1991 is an artifact of these revisions. (2) SEDS data includes some consumption of petroleum fuels for non-energy purposes. Non-energy use results in some sequestration of carbon, which otherwise would be released if the fossil fuel had been burned for energy. The fuels affected are transportation lubricants, industry lubricants, a portion of industry LPG and a portion of "other" petroleum. This study assumes that the percentage of these fuels consumed for non-energy uses from 1991 to 1996 equaled

	Source	Methodological notes
		the percentage in the 1990 baseline year. Estimates of CO_2 emissions from non-energy uses are documented in Chapter 4, Section 1 of this study. (3) SEDS provides consumption data through 1994. Regression on 1982 to 1994 consumption trends was used to estimate industrial, in residential and commercial petroleum consumption for 1995 and 1996. The apparent reduction in residential and commercial CO_2 emissions from petroleum use between 1994 and 1995 is an artifact of this methodology.
Thermal conversion factors (Btus/ton) for coal consumed by utility plants, 1990-96	EIA, Cost and Quality of Fuels for Electric Utility Plants: Table 36 for 1990 and 1991, Table 24 for 1992 to 1996	(1) These thermal conversion factors are specific for each plant and year. (2) The thermal conversion factor for coal burned by a plant during the year was assumed to equal the thermal conversion factor for coal received by the plant during that year. (3) For each plant and year, the thermal conversion factor for coal receipts was estimated as a weighted average of thermal conversion factors for coal from each state of origin, weighted by quantity of coal received from that state. (4) The weighted average thermal conversion factor for all plants was used to estimate Btu consumption for several small municipal plants that reported no cost-and-quality data.

	Source	Methodological notes
Thermal conversion factors for coal consumed by other sectors and for natural gas	EIA, State Energy Data Report 1994, Appendix D	Appendix D provides thermal conversion factors by sector for the years 1960 to 1994. The 1994 thermal conversion factors were used for years after 1994.
Thermal conversion factors for petroleum	State Workbook, Chapter 1	
Carbon coefficients (lbC/MBtus) to estimate CO_2 emissions from coal burned by utilities, 1990-96	EIA, Cost and Quality of Fuels for Electric Utility Plants: Table 36 for 1990 and 1991, Table 24 for 1992 through 1996; and Hong, B.D. and E.R. Slatick, Carbon Dioxide Emissions Factors for Coal, EIA, Quarterly Coal Report, January-March, 1994, pp. 1-8	(1) These coefficients are specific for each plant and year. (2) The carbon coefficient for coal burned by a plant during the year was assumed to equal the thermal conversion factor for coal received by the plant during that year. (3) For each plant and year, the carbon coefficient for coal receipts was estimated as a weighted average of carbon coefficients for coal from each state of origin, weighted by the quantity of coal received from that state. (4) The weighted average carbon coefficient for all plants was used to estimate CO_2 emissions for several small municipal plants that reported no cost-and-quality data. (5) Strictly speaking, carbon content of coal is not determined by which state the coal is mined in, but rather by the organic material the coal originated from, as well as the burial conditions of the material and the temperatures to which the material was subjected in the subsurface. Coals of different carbon contents may originate in the same state; it is the coal seam being mined that determines the carbon content. However,

	Source	Methodological notes
		data on the origin and carbon content of coal used by utilities does not exist at the coal seam level; therefore, it was necessary to use the state-level estimates provided by EIA.
Carbon coefficients (lbC/MBtus) to estimate CO_2 emissions from coal combustion by utilities prior to 1990 and by other sectors for all years	EIA, State Energy Data Report 1994, Appendix F	Appendix F provides statewide carbon coefficients by sector for the years 1980 to 1994. The 1980 coefficients were used for years prior to 1980, and the 1994 coefficients were used for years after 1994.

Greenhouse Gas Emission Trends and Projections for Missouri, 1990-2015 Technical Report

Chapter 3

Projections of CO_2 Emissions from Fossil Fuel Combustion in Missouri's Utility Sector, 1997-2015

Chapter 3: Projections of CO_2 emissions from fossil fuel combustion in Missouri's utility sector, 1997-2015

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Chapter 3: Estimates of future CO_2 emissions from fossil fuel combustion in Missouri's utility sector

Combustion of fossil fuels to generate electricity is the single largest source of CO_2 emissions in Missouri. In 1996, 48 percent of CO_2 emissions from energy use originated in the utility sector. Changes in the utility sector's use of coal and other fossil fuel resources can dramatically affect the overall level of greenhouse gas emissions in the state, as occurred between 1994 and 1996.

The primary task involved in projecting utility CO_2 emissions is to project the quantity of coal, petroleum and natural gas that will be burned by utilities to generate electricity. The specific mix of fuels is important because coal contains more carbon than petroleum and petroleum contains more carbon than natural gas. Projected CO_2 emissions are estimated from projected fossil fuel consumption using methods similar to those used in the *1990 Inventory* and in Chapter 2.[1]

Part 1 of this chapter projects utility fossil fuel combustion relying on three fairly straightforward "direct" methods, as follows:

- the SS (Steady State) method, which bases its projections on the rate of state population growth;
- the CT-direct (Continuing Trend) method, which bases its projections on simple linear regression from past fossil fuel combustion trends; and
- the AEO-direct (*Annual Energy Outlook*) method, which bases its projections on extrapolation from the *Annual Energy Outlook 1997*.[2]

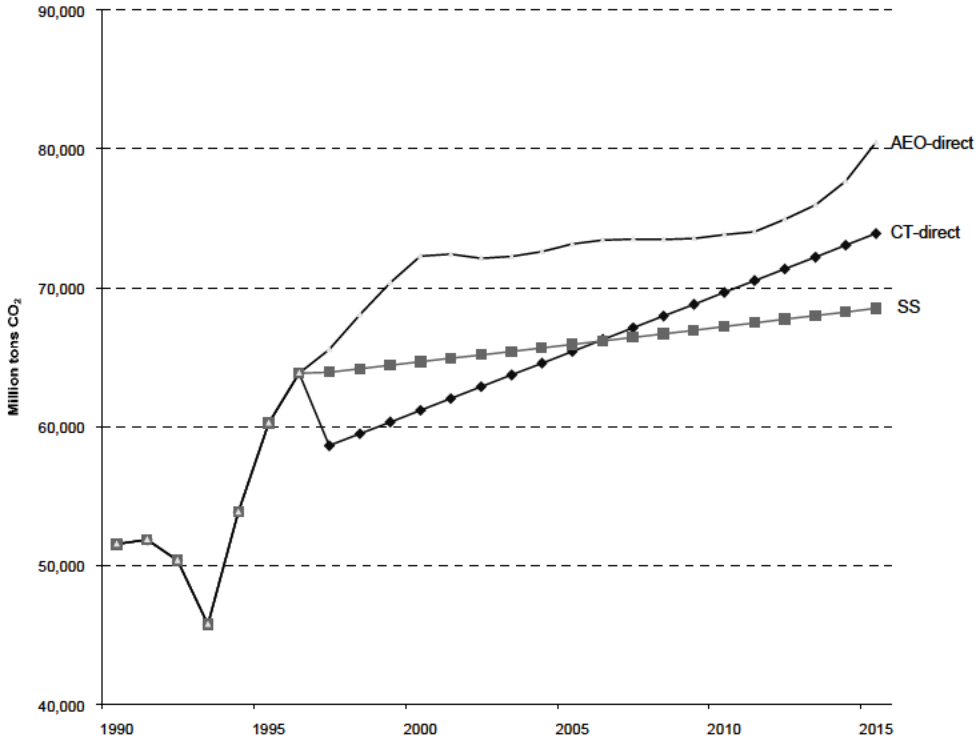
These three "direct" methods, in addition to their use in Part I of this chapter, are also used in Chapter 4 to project fossil fuel combustion in Missouri's residential, commercial, industrial and transportation sectors. Although the SS method is probably inappropriate for projecting utility generation and fossil fuel use, it is included in this chapter for consistency with the presentation in Chapter 4.

[1] The primary change in methodology is that the emissions projections in this chapter rely on a single state-specific CO_2 coefficient to estimate statewide CO_2 emissions from coal combustion. The Missouri coefficient is taken from the USDOE/EIA, *State Energy Data Report 1994*, Appendix F. In Chapter 2, CO_2 emissions from utility coal combustion are estimated on a plant-by-plant basis using CO_2 coefficients that are derived for each plant.

[2] USDOE, Energy Information Administration, *Annual Energy Outlook 1997.*

Chart 1 summarizes the utility emissions projections that result from applying these "direct" methods to utility fossil fuel use. In terms developed later in this chapter, the AEO-direct projection is a mid-range projection, and the CT-direct projection is a low-emissions projection.[3]

Chart 1 - Projected CO_2 emissions from the Missouri utility sector, estimated by direct methods, 1990-2015



Part 2 of this chapter extends the analysis of utility emissions beyond the relatively simple "direct" estimation methods developed in Part 1. For projections of CO_2 emissions from energy use in the residential, commercial, industrial and transportation sectors, the direct methods were deemed sufficient. However, for utility sector projections, an extension beyond the direct methods was deemed appropriate because (1) electric generation is the single most important source of CO_2 emissions in Missouri and (2) projections are particularly problematic in the utility sector due to uncertainty about the timing and nature of utility restructuring in the state.

[3] The CT projection in Chart 1 appears to project a reduction in emissions between 1996 and 1997. This is an artifact of the assumption of linearity inherent in simple linear regression. Since short-term trends in utility fossil fuel use are clearly non-linear, the CT-direct method is more usefully viewed as a projection of long-term trend.

Although it is beyond the scope of this study to deal with the full range of uncertainties related to utility restructuring, the extended analysis in Part 2 attempts to incorporate two major factors that are likely to affect future utility CO_2 emissions — (1) projected in-state electricity sales and (2) future utility use of natural gas to generate electricity.

The level of electricity sales is important because CO_2 emissions result from electricity generation, and electricity generation is driven by sales. The level of utility natural gas use is important because natural gas has about 44 percent lower carbon content than coal. It has been estimated that on a full fuel-cycle basis, a highly efficient natural gas-fired turbine produces nearly two-thirds less greenhouse gases than a coal-fired facility.[4]

As Table 1 indicates, the extended analysis in Part 2 of this chapter projects two levels of in-state electricity sales (CT and AEO[5]) and two levels of natural gas use (high and low), resulting in four extended scenarios.

Table 1 - Extended methodology scenarios for Missouri utility CO_2 emissions in 2015

	Low natural gas use (15-30 trillion Btus)	**High natural gas use** (about 100 trillion Btus)
High (CT) electricity sales (projects 88.5 billion kWh in 2015, based on CT method for projecting in-state electricity sales)	**CT-LowNG** (88.6 million tons CO_2 in 2015, a 2.2% growth rate between 1990-2015)	**CT-HighNG** (82.1 million tons CO_2 in 2015, a 1.9% growth rate between 1990-2015)
Low (AEO) electricity sales (projects 81.5 billion kWh in 2015, based on AEO method for projecting in-state electricity sales)	**AEO-LowNG** (80.9 million tons CO_2 in 2015, a 1.8% growth rate between 1990-2015)	**AEO-HighNG** (73.9 million tons CO_2 in 2015, a 1.5% growth rate between 1990-2015)

The CO_2 projections in Table 1 can be divided into high, midrange and low estimates:

- The CT-LowNG scenario projects a level of emissions substantially higher than any projected using the direct methods. According to this scenario, utility CO_2 emissions in 2015 will be 72 percent higher than utility emissions in 1990.

[4] M.A. Deluchi, *Emissions of Greenhouse Gases for the Use of Transportation Fuels and Electricity*, Volume 1, Argonne National Laboratory, p. 54.

[5] So named because linear regression (CT) methods project relatively high electricity sales whereas extrapolation from the *Annual Energy Outlook 1997* (AEO) results in a lower projection of electricity sales.

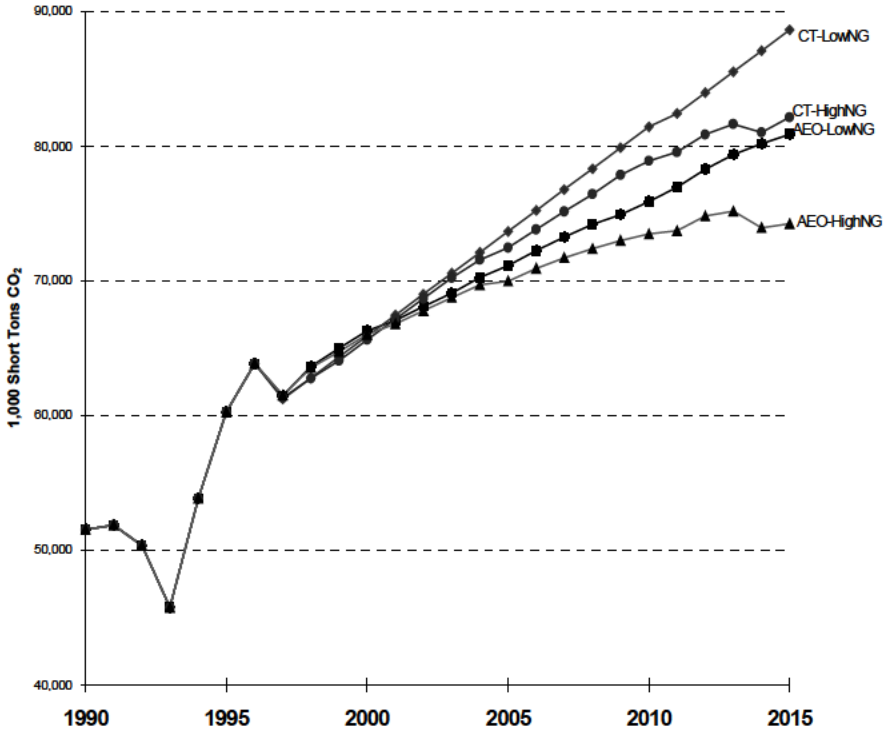
- The CT-HighNG and AEO-LowNG scenarios project emissions in the same middle range as the AEO-direct projection. According to this scenario, utility CO_2 emissions in 2015 will be approximately 56 to 59 percent higher than in 1990.

- The AEO-HighNG scenario projects a relatively low level of emissions in the same range as the CT-direct projection. According to this scenario, utility CO_2 emissions in 2015 will be 43 to 44 percent higher than in 1990.

Charts 2 and 3 illustrate the clustering of these projections into high-, midrange- and low-CO_2 estimates.[6] Chart 2 illustrates the CO_2 emissions projected by the four extended scenarios. Chart 3 is similar, but includes the AEO-direct and CT-direct projections.

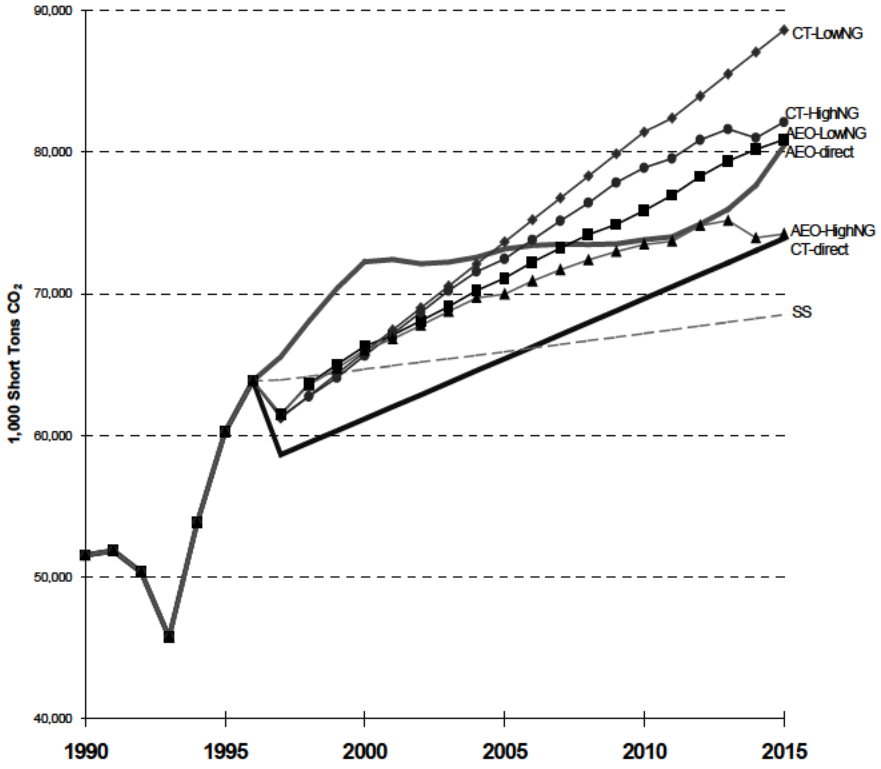
It should be noted that "low emissions" is a relative term, since the "low" projections are for a very substantial 43 to 44 percent increase in utility emissions over 1990 levels.

Chart 2 - Projected CO_2 emissions from the Missouri utility sector, estimated by extended methodology, 1990-2015



[6] Chart 3 also illustrates the SS projection, which is lower than the "low-emissions" projections discussed in the text. As noted above, the SS projection method is probably inappropriate for utility emissions but is included for completeness.

Chart 3 - Projected CO_2 emissions from the Missouri utility sector, estimated by direct and extended methodologies, 1990-2015



The four extended scenarios are not intended to be exhaustive. Many factors not explicitly incorporated in Table 1 could influence in-state electricity generation and CO_2 emissions.[7]

(1) Future utility sales and energy input choices could be affected by state or federal restructuring policy decisions, such as requirements to include renewable energy in the mix of energy sources used to generate electricity ("portfolio requirements") or legislation creating new funding sources for demand-side management programs.

(2) Variation in demographic factors, economic growth or the rate of technological innovation could lead to in-state sales that are higher or lower than those used in the extended scenarios.

[7] Factors considered in the risk analysis portions of the AmerenUE and Kansas City Power and Light (KCPL) Integrated Resource Plans are representative. AmerenUE, *Energy Resource Plan*, June 1995, p. 15; Kansas City Power and Light (KCPL*), KCPlan 94: Integrated Resource Plan (1995-2014*), Volume 1: Summary.

In both the U.S. and Missouri, electricity sales have steadily increased since the 1960s, but the average annual rate of increase has slowed over time. The extended scenarios assume the average annual rate will either remain steady (CT-sales scenarios) or continue to decrease (AEO-sales scenarios).

The high-sales (CT-sales) scenarios in Table 1 project 88.5 billion kilowatt-hours (kWh) of in-state electricity sales in 2015. These scenarios assume that sales to end users in Missouri's residential, commercial and industrial sectors will continue to follow 1984 to 1996 trends. These scenarios project an average annual growth rate through 2015 of about 1.8 percent per year, slightly below the projected 1.9 percent growth rate for gross state product.

The low-sales (AEO-sales) scenarios in Table 1 project 81.5 billion kilowatt-hours (kWh) of in-state electricity sales in 2015. This scenario is derived from the EIA's *Annual Energy Outlook 1997* projections for residential, commercial and industrial electricity sales in the North West Central census region and reflects the *Annual Energy Outlook's* assumption that future growth in electricity sales will slow to levels below the 1984 to 1996 trend. Part 2, Section 1 discusses EIA's reasoning for this assumption.

The low-sales scenarios project an average annual growth rate through 2015 of about 1.36 percent per year. This is lower than the *Annual Energy Outlook's* projections for national electricity sales (1.44 percent) and regional electricity sales (1.64 percent). The rate is below national and regional projections because Missouri population growth is expected to be slower than national and regional population growth.[8]

Both the high-sales and low-sales estimates may be conservative. Some Missouri utilities assume higher sales growth than those used in these scenarios.

For example, Springfield City Utilities, the municipal utility with the greatest generating capacity in Missouri, currently assumes that over its planning horizon electricity sales will grow at about 3 percent per year, with about 1.7 percent due to an increasing consumer base and 1.3 percent due to increased sales per consumer.[9]

AmerenUE and Kansas City Power and Light (KCPL), the two largest investor-owned utilities in Missouri, account for about 57 percent of in-state sales to electricity end users.[10]

In its 1994 and 1995 Integrated Resource Plans (IRPs), AmerenUE forecasted annual sales growth of 1.8 percent through 2005, and KCPL forecasted annual sales growth of 2.3 percent through 2015.[11]

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[8] Some utility planners assume higher sales growth than those used in these scenarios. For example, the Springfield municipal utility currently assumes that its electricity sales will grow at about 3 percent per year.

[9] Personal communication, Cathy Meyer, Manager-Rates & Fuels, 06/17/97.

[10] This estimate is based on analysis of utility-level USDOE/EIA data compiled from reports submitted by Missouri utilities using Form EIA861.

[11] Union Electric (UE), now AmerenUE, *Energy Resource Plan*, June 1995, p. 15; Kansas City Power and Light (KCPL*), KCPlan 94: Integrated Resource Plan (1995-2014*), Volume 1: Summary, p. III-4.

(3) Technological, economic and institutional factors could lead to utility levels of natural gas that are higher or lower than those used in the scenarios.

Over time, the rate of increase in Missouri utility electricity sales will determine how much additional base load power must be generated or otherwise acquired to meet increased demand.[12] At present, base load generation of electricity from coal-fired boilers accounts for about 99 percent of utility CO_2 emissions. Generating capacity sets an upper limit on CO_2 emissions from coal. Part 2, Section 3, estimates that Missouri utilities could generate up to 85 million tons of CO_2 per annum from coal-fired boilers at present.

In the intermediate to long run, the upper limit on CO_2 emissions may increase or decrease as utilities choose to construct new plants or repower existing plants. The scenarios in Part 2 are constructed assuming the primary candidates for additional intermediate or base load generation are coal- or natural gas-based generation technologies.[13]

Currently, Missouri utilities use natural gas primarily to meet peak load demands. As described in Part 1, Section 2, the high and low natural gas scenarios in Table 1 are both based on *Annual Energy Outlook 1997* projections, but use different methods to extrapolate from these projections. The *Annual Energy Outlook 1997* anticipates an expanded role for natural gas over the next 20 years.

The high natural gas scenarios anticipate that Missouri utilities will follow national trends and use natural gas as an energy source for generating intermediate and base load power, displacing some coal use. The low natural gas scenarios, in contrast, assume that Missouri utilities will increase their use of natural gas to meet peak load requirements and will build some intermediate generating capacity, but will not add significant natural gas base load generating capacity.

Under the low natural gas scenarios, Missouri utilities will continue to rely primarily on coal. The CT-LowNG scenario projects that new coal-fired capacity will be required and built after 2011, whereas the AEO-LowNG scenario projects that requirements for coal-fired generation can be met by the state's current coal-fired capacity. Total CO_2 emissions under the these two scenarios are about 6 to 6.5 million tons higher than CO_2 emissions from the corresponding scenarios that assume base generation from natural gas.

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[12] Demand-side management (DSM) is an alternative to generation or purchase and is treated as such in the AmerenUE and KCPL Integrated Resource Plans. However, a number of Missouri utilities appear to view DSM primarily as a means to reduce peak load rather than base load. Because the current analysis is intended to serve as a business-as-usual projection, it is assumed that DSM programs are maintained but not expanded.

[13] In a latter phase of the project, the analysis will be extended to incorporate renewable sources and fuel cells. The present analysis is focused on supply-side generation sources for which utilities have shown a current preference and for which there are data on past utility consumption. The AmerenUE and KCPL Integrated Resource Plans cited in Footnote 29 considered many supply-side options, but the preferred options were generally for constructing or repowering coal- and natural gas-fired units.

However, the level of Missouri natural gas use could fall outside the range of the scenarios in Table 1 for two reasons:

- *Annual Energy Outlook* projections of regional utility natural gas use are based on assessment of many economic and technological factors. However, the regional projections are subject to a high level of uncertainty. Technological and economic factors may influence the price, availability and relative attractiveness of natural gas and natural gas-based generating technologies, leading to higher or lower levels of natural gas use than those incorporated in the scenarios.

- Extrapolation from regional projections does take into account state or institutional factors that may influence utility decisions on construction and utilization of natural gas generating facilities. Past Missouri utility decisions have indicated a preference for purchasing power rather than building new natural gas generating capacity. Under restructuring, the availability of purchased power may increase or decrease.

(4) Table 1 does not incorporate possible changes in the level and balance of export sales and purchases from outside Missouri. All four scenarios assume that Missouri will continue to be a net exporter of electricity and that exports will continue to be small in proportion to in-state sales. Under a restructured market, it is possible that net exports could change significantly. A large increase in net exports could lead to an increase in coal-fired generation and larger increases in CO_2 emissions than projected in this chapter. An increase in net imports would probably reduce future CO_2 emissions from projections.

Even under the current regulated environment, wholesale power sales purchases have been an important aspect of utility planning. If restructuring occurs, there may be major shifts in the customer base of Missouri utilities. A logical next research step would be to formulate scenarios that explicitly incorporate possible shifts in electricity exports and imports, and to assign probabilities and CO_2 "payoffs" to each scenario. These were not incorporated into the current report due to lack of sufficient data.

Part 1: Direct estimates of future utility fossil fuel use and CO_2 emissions

Three different methods were used to directly estimate future use and CO_2 emissions from utility use of petroleum, natural gas and coal:

- the "Steady State" (SS) method, which assumes that fuel use increases at the rate of population growth;
- the "Continuing Trend" (CT) method, which projects future use through regression analysis of past trends;
- the "*Annual Energy Outlook*" method, which extrapolates from regional estimates in the *Annual Energy Outlook 1997* (AEO), adjusted to take into account the projected rate of state population growth relative to regional population growth.

The petroleum and natural gas estimates were used as input into the model developed in Part 2, and the coal estimate was used as a reference point for the estimates of coal consumption developed in Part 2.

Section 1: Projected CO_2 emissions from utility petroleum use

In 1996, Missouri utilities operated petroleum-fired generating facilities with a summer capability of 1,710 megawatts. The *Inventory of Power Plants in the United States* reports 452 megawatts of planned additions burning petroleum; however, with the exception of several small internal combustion units planned by municipalities, most of the units listed in the Inventory are dual-fired units that will primarily burn natural gas.[14]

Petroleum's principal role is to provide peak load power or a backup fuel for dual-fired units. Missouri utility use of distillate and residual fuel peaked in 1978 at 16 trillion Btus and during 1990 averaged 1 to 2 trillion Btus.

Table 2 and Chart 4 present estimates from the SS, CT and AEO methods. All three methods project that utility petroleum consumption will remain below 3 trillion Btus through 2015 and that CO_2 emissions will remain below 0.25 million tons.

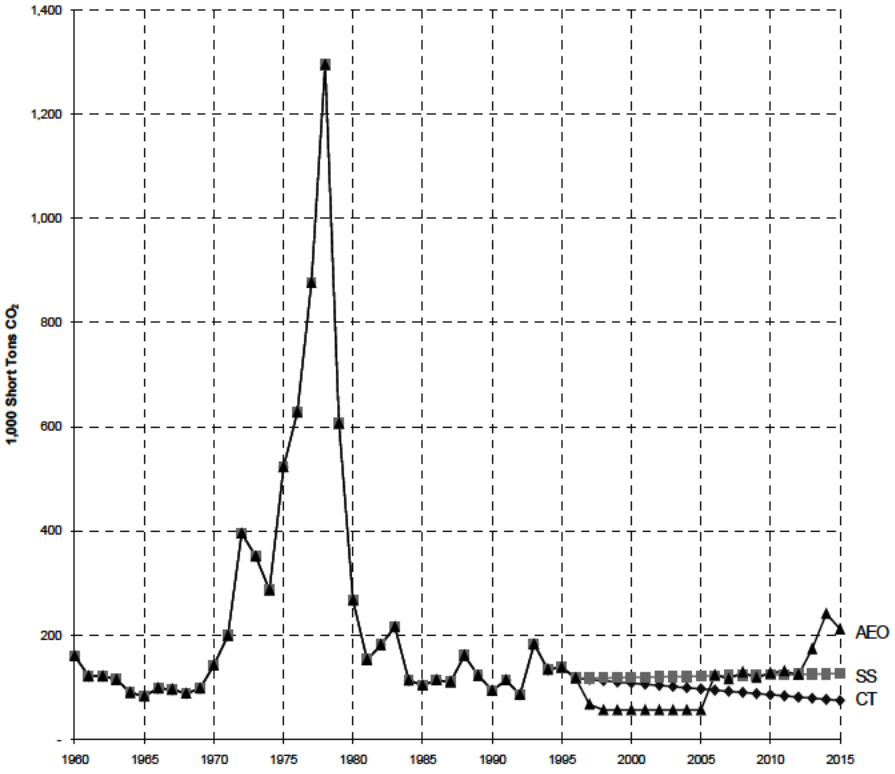
[14] USDOE/EIA, *Inventory of Power Plants in the United States as of January 1, 1996*, Table 17; personal communication, Dan Beck, Missouri Public Service Commission, 06/03/97.

Table 2 - Projected CO_2 emissions from Missouri utilities' use of petroleum to generate electricity, by direct projection method

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	93	138	118	121	123	125
Continuing Trend	93	138	107	96	85	74
AEO	93	138	56	56	127	211

Chart 4 - Steady State (SS), Continuing Trend (CT) and AEO direct projections of utility CO_2 emissions from combustion of petroleum

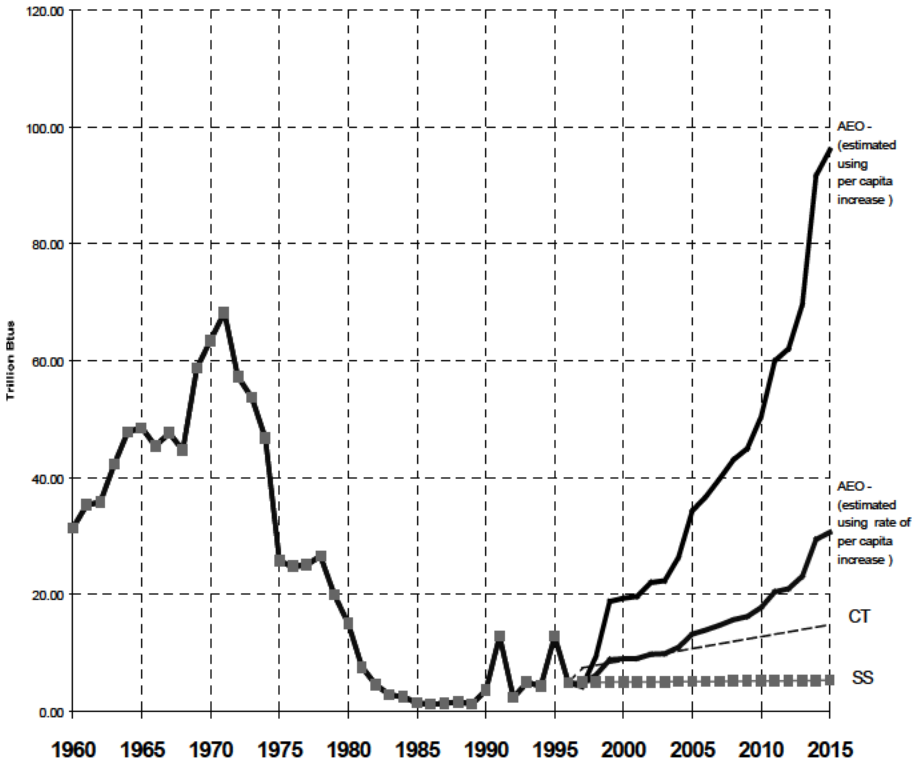


Section 2: Projected CO_2 emissions from utility natural gas use

In 1996, Missouri utilities operated natural gas-fired generating facilities with a summer capability of 1,205 megawatts, with planned additions scheduled for more than 2,000 megawatts including dual-fired units.[15] As Chart 5 illustrates, utility natural gas consumption peaked in 1971 at about 68 trillion Btus and has exceeded 10 trillion Btus only twice since 1980.

As Chart 5 illustrates, the SS and CT methods project only a small increase in utility natural gas use. The chart provides two separate AEO projections, both of which are substantially larger than the SS and CT projections. Given utility plans to more than double capacity, the AEO projection is much more credible than those from the other two methods. By their nature, the SS and CT methods take only current or past utility fuel use into account and cannot incorporate structural changes in energy use.

Chart 5 - Estimated utility natural gas use, 1960-2015



[15] USDOE/EIA, *Inventory of Power Plants in the United States as of January 1, 1996*, Table 17.

Both AEO projections in Chart 5 are based on the *Annual Energy Outlook 1997* projection for utility natural gas use in the West North Central region. Both are adjusted to account for Missouri's lower rate of population growth.

The lower AEO projection for Missouri utility natural gas use in 2015 was estimated by assuming that per capita natural gas use of Missouri utilities will increase at the same rate as per capita use in the rest of the region. The resulting projection, 30.6 trillion Btus in 2015, represents an annual growth rate of about 10.1 percent, comparable to the 10.5 percent growth rate that AEO projects for the region as a whole.

However, the *Annual Energy Outlook 1997* estimates that utility consumption of natural gas in the North West Central region as a whole will increase by 380 trillion Btus, from about 60 trillion Btus in 1995 to more than 400 trillion Btus in 2015. The lower projection implies that less than 10 percent of this expansion will occur in Missouri.

The higher AEO projection was estimated by assuming that Missouri per capita use will increase by the same amount as per capita use in the rest of the region. It implies that about 30 percent of the region's expansion in natural gas use will occur in Missouri, about the same as Missouri's share of total utility sales in the region.

One justification for considering both a low and high AEO projection is that a fairly large degree of uncertainty is associated with projections of utility natural gas use. In the 1997 edition of the *Annual Energy Outlook*, EIA's reference case projections for utility natural gas use in 2015 were higher than the projections by three other major forecasting sources.[16] A year later, EIA's projections had not changed much, but the revised projections by two of the other three forecasting sources were higher than the projections in the 1998 edition of *Annual Energy Outlook.*

A second justification is that the projection must be based on the outcome of future decisions by Missouri utilities. The lower projection represents a decision to continue using natural gas primarily to provide peak load requirements. The higher projection represents a decision to use natural gas to provide intermediate and base-load, as well as peak-load, power.

Utility decisions will be influenced by a variety of factors that will reinforce or disrupt the status quo. In addition to fuel price, these include sales demand, technological change and political decisions such as restructuring and environmental regulation.

The USDOE/EIA National Energy Modeling System (NEMS) model used to develop the *Annual Energy Outlook 1997* projections includes a linear optimization module for projecting technology choices in the utility sector. The NEMS model projects that new natural gas facilities will outnumber new coal steam plants by a 4-to-1 margin. This would include widespread addition of natural gas combined-cycle turbines suitable for midrange and base-load generation. Factors favoring such a decision include relatively low capital requirements, short construction lead times and high conversion efficiency of natural gas turbines and combined-cycle technology.[17]

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[16] *Annual Energy Outlook 1997*, Table 20, p. 80, and Table F8, p. 190; and personal communication, David Shoeberlein, USDOE/EIA, 06/23/97.

[17] *Annual Energy Outlook 1997*, p. 49; personal communication, David Shoeberlein, USDOE/EIA, 06/17/97.

Similarly, a recent USEPA analysis projects that new generating facilities will be based on natural gas rather than coal.[18] The USEPA analysis projects that electric generation in the U.S. will continue to grow over the next 15 years, that low-cost coal-fired units will improve their capacity and have greater accessibility to potential customers by 2000, and that most increases in generation through 2010 will be supplied by coal-fired electric generation units.

However, USEPA also projects that the increase in generation by coal-fired units after 2000 will occur through their increased use of existing capacity as they gradually increase their output to keep pace with demand, and that no new coal-fired units will be built after 2000. Instead, from 2000 to 2010, improvements in combined-cycle technology and relatively low natural gas prices will lead the power industry to substantially increase its gas combined-cycle capacity. The capacity increases would come from construction of new gas combined-cycle as well as the repowering of some existing oil/gas steam units as combined-cycle gas units.

Missouri utilities' preference for natural gas could also be influenced by a recent USEPA rule intended to reduce nitrogen oxides (NO_x) emissions in Missouri and several other states. In September, 1998, USEPA announced a final rule setting summer season[19] NO_x budgets for Missouri, 21 other states and the District of Columbia and requiring state implementation plans (SIPs) to meet these budgets. Missouri and the other states must submit their plans by September 1999 and implement them by May 1, 2003.

In late Spring, 1998 the U.S. Court of Appeals for the District of Columbia Circuit granted a motion for partial stay of USEPA's rule until April 2000. The following discussion addresses the likely impact if the USEPA rule is eventually implemented.

The purpose of this rule, commonly known as the NO_x SIP call, is to reduce regional transport of ground-level ozone that currently affects several northeastern states.[20] Although the NO_x SIP call does not officially mandate the content of the state implementation plans, USEPA analyses, and model plans leading to the SIP call, have presumed that state plans will focus on reducing NO_x emissions from utilities and other major point sources.[21]

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[18] USEPA, Analyzing Electric Power Generation Under the CAAA. This study and other documents based on USEPA's use of the Integrated Planning Model (IPM) may be found at USEPA's IPM site, http//www.epa.gov/capi/otagmain. html. USEPA adopted IPM in 1995 as the basis for baseline and policy analysis of electric generation and emissions. IPM was developed by ICF Resources, a consulting firm.

[19] Summer season is the period May 1 through September 30.

[20] The action arose because the difficulty experienced by several northeastern states in meeting the ground-level ozone requirements of the Clean Air Act was attributed to NO_x emissions originating in other states, including Missouri. NO_x reacts in the atmosphere to form compounds that contribute to the formation of ozone. These compounds, as well as ozone itself, can travel hundreds of miles across State boundaries to areas such as the eastern U.S. that are far from the source of the pollution.

[21] USEPA's announcement of the final rule in September, 1998 was preceded by two years of discussion of the ozone transport issue within the Ozone Transport Assessment Group (OTAG), a partnership with the 37 easternmost States and the District of Columbia, industry representatives, and environmental groups. In June 1997, the OTAG states voted 32-5 in favor of a strategy to reduce NO_x emissions from utilities and other major point sources. In November, 1997, after a review of OTAG's analysis, findings, and recommendations, USEPA proposed a rule to limit summer season NO_x emissions with specific budgets for each state to be included in the rule. USEPA subsequently developed a NO_x Model Cap and Trade Rule to provide an emissions trading framework within the ozone transport rulemaking.

Utility compliance with the rule might result in greater use of natural gas than would otherwise occur. Of the many options for complying with the rule, several would tend to result in substitution of natural gas for coal consumption. Two options would directly increase natural gas: (1) repowering coal plants — for example, converting them to natural gas combined cycle plants; and (2) retiring them and replacing them with combined cycle plants. This would lead to year-round increases in natural gas use.

In addition, natural gas use could increase if utility dispatch decisions during summer months change to favor low-NO_x sources of power. However, changing dispatch rules would lead to a significant increase in natural gas use only if there are relatively low natural gas prices and if a number of recent-technology natural gas plants such as combined cycle plants have already been built. Natural gas-fired generation would have to compete with other low-NO_x sources such as nuclear plants, hydroelectric generation and wholesale purchase. Some coal plants — including certain coal plants in Missouri — are also low NO_x emitters and would be favored, but many older coal plants tend to be high NO_x emitters and would be less used.

However, the impact of the rule on natural gas use will probably be minor because, according to USEPA impact analysis of the NO_x SIP call, utilities will probably comply with the rule primarily by placing controls on coal plants rather repowering them or shutting them down. USEPA projects that "almost all of the coal-fired capacity is retrofitted with some NO_x control equipment under the Proposed Regulatory Approach. However, most of the oil and gas steam units are not retrofitted with control technology [and] no existing combined-cycle units are forecast to add pollution controls." [22] The rule would be most likely to lead to a coal plant's retirement if the plant is marginally profitable and if the utility anticipates that the plant will require an additional investment in carbon emissions controls in the future.

The factors tending to increase Missouri utilities' natural gas use must be weighed against certain factors that could limit Missouri utilities' reliance on natural gas. These factors include the following: (1) the preference of some Missouri natural gas utilities that natural gas, as a premier fuel, be used for purposes other than utility power generation[23]; (2) possible limits on pipeline capacity; and (3) the price impact of increased demand for natural gas.

USEPA, like EIA, relies on NEMS for "base case" projections of natural gas prices. The NEMS base case assumes that natural gas prices will remain fairly stable through 2015 as the result of new technology for natural gas exploration and recovery. In the alternative "low technology" case, supply limitations are expected to put upward pressure on natural gas prices, which would result in a shift of a large portion of new utility construction from natural gas to coal.

[22] USEPA, April 1998, Chapter 2, *Electric Power Industry*, p. 2-18.

[23] Reviewer comment by Omar Yaakub, Laclede Natural Gas, 6/98.

In their capacity planning process, Missouri utilities have given favorable consideration to combined-cycle units or other natural gas technologies suitable for intermediate and base-load generation. However, no large Missouri utility has built or announced plans to build such units, partly because of favorable wholesale purchase opportunities and partly because of the uncertainties over future natural gas supply and prices described above.[24]

The estimates of utility CO_2 emissions from natural gas use presented in Table 3 and Chart 6 include both the low and high AEO projections. The expansion of natural gas extrapolated from AEO projections would imply 5.6 million tons of CO_2 emissions at the higher level of use and 1.8 trillion tons at the lower level of use.

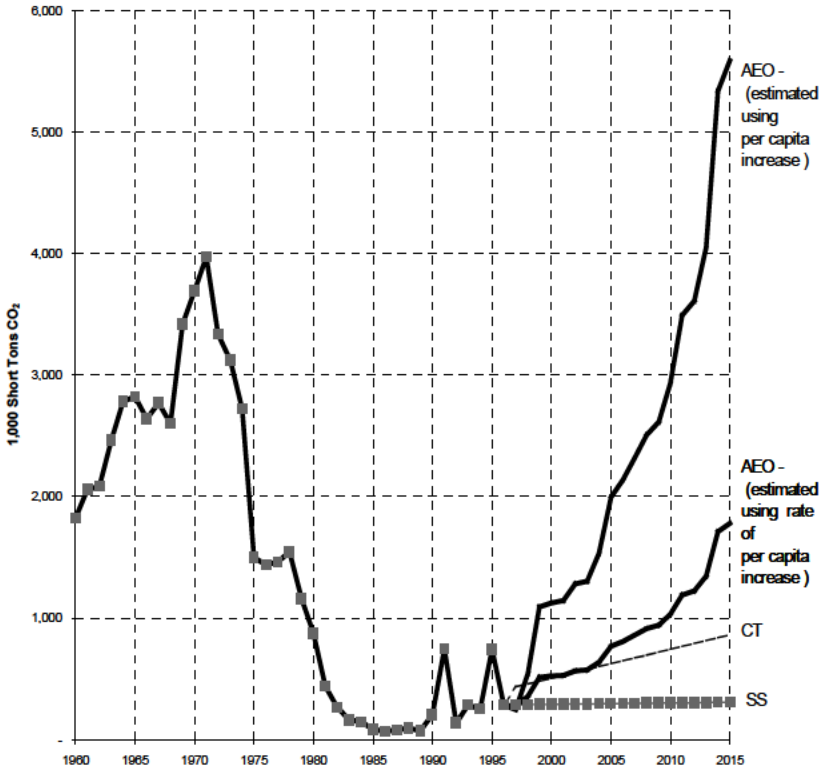
Table 3 - Projected CO_2 emissions from Missouri utilities' use of natural gas to generate electricity, by direct projection method

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1996	2000	2005	2010	2015
Steady State	207	284	290	296	302	308
Continuing Trend	207	284	505	624	743	862
AEO - HighNG use	207	284	1,126	1,995	2,931	5,589
AEO - LowNG use	207	284	523	768	1,032	1,781

[24] On more than one occasion, regulated utilities undergoing the IRP process have considered construction of an advanced natural gas facility but have preferred to pursue wholesale purchase contracts for the power the facility would have provided. However, KCPL has operated a recently added natural gas unit at about 25 percent capacity — higher than normal use of a peak-load facility — because it has found it is economical to do so. Personal communication, Dan Beck, Missouri Public Service Commission, 06/03/97.

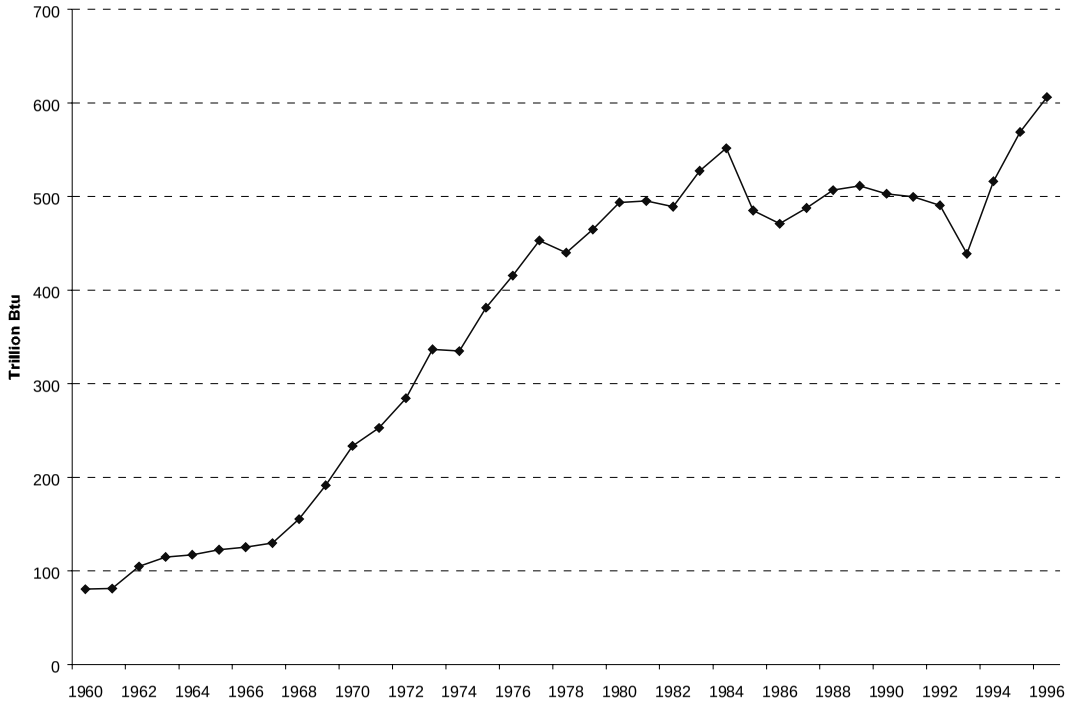
Chart 6 - Steady State (SS), Continuing Trend (CT) and AEO direct projections of utility CO_2 emissions from combustion of natural gas



Section 3: Projected CO_2 emissions from utility coal use

In 1996, Missouri utilities operated coal-fired generating facilities with a summer capability of 10,575 megawatts. No additional coal-fired units are planned at this time.[25] Utility coal consumption in Missouri reached a peak of about 550 trillion Btus in 1984, dropped by about 80 trillion Btus after the Hallway nuclear power plant came on line in 1984-86, and recently increased to record consumption of about 570 trillion Btus in 1995 and 602 trillion Btus in 1996. Chart 7 illustrates the pattern of utility coal use through 1996.

Chart 7 - Missouri utility coal use, 1960-96



[25] USDOE/EIA, *Inventory of Power Plants in the United States as of January 1, 1996*, Table 17.

Part 2 of this chapter focuses on estimating utility coal consumption and CO_2 emissions based on projections of electricity sales. However, the SS, CT and AEO methods were also applied to directly estimate future coal consumption without reference to electricity sales. The resulting projections were spread from a low projection of about 650 trillion Btus (SS method) to a high projection of about 750 trillion Btus (AEO method).

The previous discussion of natural gas describes two methods for extrapolating AEO regional projections to Missouri. Although the two methods result in divergent projections for utility natural gas use, they are in fairly close agreement on future coal use. If Missouri per capita coal use increases at the same rate as per capita use in the rest of the region, the resulting projection is for 768 trillion Btus, a 1.3 percent growth rate. If it increases by the same amount as per capita use in the rest of the region, the resulting projection is for 753 trillion Btus, a 1.1 percent growth rate. The latter method is used for coal and the other fuel projections in this report.

Table 4 summarizes the projections of CO_2 emissions resulting from the three methods for directly estimating utility coal use. Chart 1 in the introduction to this chapter provides graphic illustration of the three direct estimates of utility CO_2 emissions from coal.

Table 4 - Projected CO_2 emissions from Missouri utilities' use of coal to generate electricity, by direct projection method

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	51,238	59,362	64,255	65,493	66,771	68,083
Continuing Trend	51,238	59,362	60,561	64,693	68,825	72,957
AEO	51,238	59,362	71,730	72,378	72,751	78,584

Part 2: Projections of utility fossil fuel use and CO_2 emissions based on extended analysis of future electricity sales and natural gas use

The introduction to this chapter introduced the extended analysis of utility CO_2 emissions based on two primary factors: future utility natural gas use and future electricity sales. Two possible levels of natural gas use were estimated in Part 1, Section 2. Part 2, Sections 1 and 2 of this chapter estimate future in-state sales and discuss export sales.

Following these assessments of the two primary factors of the extended analysis, Section 4 develops the analytic model to be used — a simple spreadsheet accounting model used to specify the interaction of factors likely to affect future utility CO_2 emissions. Section 5 presents the model's base-case projections for the four scenarios, and Section 6 presents representative results of sensitivity analysis of assumptions used in developing the scenarios.

The model uses a sales-and-sources accounting approach to estimate CO_2 emissions. The energy sources included in the model are coal, natural gas, petroleum, nuclear and hydroelectric generation.[26] The model assumes net sales equal total power generated and depends on several variables that must be supplied from outside the model. These exogenous variables include in-state electricity sales; annual consumption of all energy resources except coal; average heat rates for generating technologies; and the distribution of an energy resource such as natural gas across generating technologies such as gas turbine or combined cycle.

Given an assumed level of sales, the model calculates the coal-fired generation required to balance electricity generation and sales and estimates the resulting CO_2 emissions from coal and other energy resources. Table 5 summarizes the methods used to model the four scenarios and compares them to the CT and AEO direct estimates in Section 1.

For its standard case, the analysis assumes that gross state product (GSP) will grow at an annual rate of 1.9 percent, identical to that used in the *Annual Energy Outlook 1997* reference case. When comparing high- and low-growth cases to the standard case, the study adopts the *Annual Energy Outlook 1997* estimates of rapid (2.4 percent), moderate (1.9 percent) and slow (1.4 percent) economic growth.[27] The analysis uses 1987 dollars to compare GSP and GNP projections. Projections of Missouri population growth are based on the State Demographer's zero-migration case projection, adjusted by addition for actual 1995 values.

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[26] In a latter phase of the project, the model will be extended to include renewable resources such as wind, solar and biomass.

[27] *Annual Energy Outlook 1997*, Table 13, p. 76, cites an identical moderate growth forecast from consulting firm DRI. By comparison, consulting firm WEFA forecasts a higher 2.2 percent rate of growth for GNP. The University of Missouri-Columbia Business and Public Administration Research Center projects a 2.315 percent growth rate for Missouri GSP through 2015, which corresponds to the WEFA forecast and the AEO/DRI rapid-growth case. Personal communication, Deenie Neff, UMC BandPA Research Center, 05/29/97.

Table 5 - Comparison of methods used to estimate future utility CO_2 emissions from fossil fuel combustion

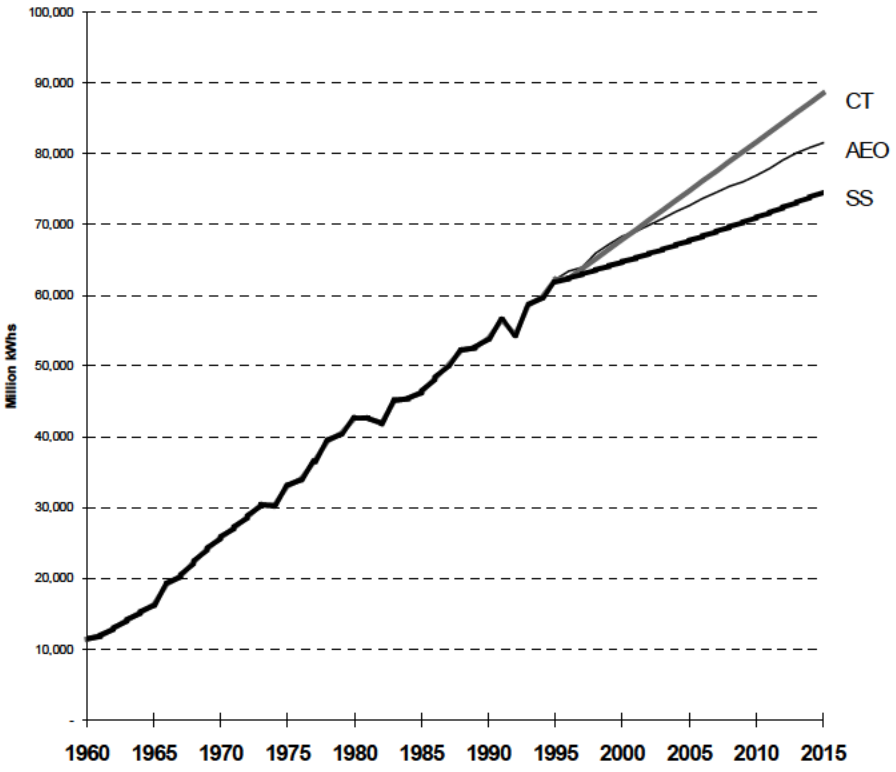
	CT direct estimate	CT sales scenario-low natural gas use	CT sales scenario-high natural gas use	AEO direct estimate	AEO sales scenario-low natural gas use	AEO sales scenario-high natural gas use
Electricity sales	N/A	Aggregated from trend analysis of past residential, commercial and industrial use; three cases based on starting year for trend analysis (1960-1994, 1970-1994 or 1980-1994)	Aggregated from trend analysis of past residential, commercial and industrial use; three cases based on starting year for trend analysis (1960-1994, 1970-1994 or 1980-1994)	N/A	Residential/commercial sales are assumed to grow at same rate as AEO sales per capita. Industrial sales are assumed to grow at same rate as AEO sales per unit of GNP, with three cases based on growth rate of GSP.	Residential/commercial sales are assumed to grow at same rate as AEO sales per capita. Industrial sales are assumed to grow at same rate as AEO sales per unit of GNP, with three cases based on growth rate of GSP.
Utility coal consumption	Based on trend analysis of past utility coal consumption	Based on heat rate and: 1) CT estimate of electricity sales, 2) estimated generation from natural gas based on CT estimate of natural gas use, and 3) CT estimates of megawatt-hour generation from other sources	Based on heat rate and: 1) CT estimate of electricity sales, 2) estimated generation from natural gas based on AEO high estimate of natural gas use, and 3) CT estimates of mWh generation from other sources	Based on AEO97 projections of utility coal use per capita	Based on heat rate and: 1) AEO estimate of electricity sales, 2) estimated generation from natural gas based on AEO low estimate of natural gas use, and 3) AEO estimates of mWh generation from other sources	Based on heat rate and: 1) AEO estimate of electricity sales, 2) estimated generation from natural gas based on AEO high estimate of natural gas use, and 3) AEO estimates of mWh generation from other sources
Utility natural gas consumption	Based on trend analysis of past utility natural gas consumption	Based on trend analysis of past utility natural gas consumption	Based on AEO97 projections of utility natural gas use per capita	Based on AEO97 projections of utility natural gas use per capita	Based on AEO97 projections of utility natural gas use per capita	Based on AEO97 projections of utility natural gas use per capita
MWh generation from natural gas	N/A	Based on natural gas consumption and heat rate distributed across technologies	Based on natural gas consumption and heat rate distributed across technologies	N/A	Based on natural gas consumption and heat rate distributed across technologies	Based on natural gas consumption and heat rate distributed across technologies
Utility petroleum consumption	Based on trend analysis of past utility petroleum consumption	Based on trend analysis of past utility petroleum consumption	Based on trend analysis of past utility petroleum consumption	Based on AEO97 projections of utility petroleum use per capita	Based on AEO97 projections of utility petroleum use per capita	Based on AEO97 projections of utility petroleum use per capita
MWh generation from petroleum	N/A	Based on petroleum consumption and heat rate	Based on petroleum consumption and heat rate	N/A	Based on petroleum consumption and heat rate	Based on petroleum consumption and heat rate

Section 1: Estimates of future in-state electricity sales

In-state electricity sales are estimated using methods based on the CT, AEO and SS approaches introduced in Section 1. Sales are projected for the three major electricity end-use sectors — residential, commercial and industrial — and aggregated into a projection of total in-state sales.

All three sales projections are pictured in Chart 8. The SS estimate, which assumes that future residential and commercial sales will grow at the rate of state population and that industrial demand will grow at the rate of GSP, projects very slow growth in residential sales (26 percent over baseline) and commercial sales (19 percent) and very rapid growth (87 percent) in industrial sales of electricity. The SS sales projections are probably not realistic and are not used as the basis for developing extended scenarios of future CO_2 emissions. However, they are presented for comparison with the CT and AEO projections.

Chart 8 - Comparison of CT, AEO and SS projections of aggregate electricity sales growth in Missouri



The CT projection pictured in Table 6 reflects the trend of electricity sales since the 1980s. Based on least-squares linear regression, it assumes that past trends in state electricity sales will continue into the future. The study's reference case for the CT sales projection is based on analysis of 1980 to 1994 trends in the residential sector and 1984 to 1994 trends in the commercial and industrial sectors.[28] Chart 9 presents the CT projections for in-state sales increases through 2015, and the projected percentage increases with respect to the base year 1990. Between 1995 and 2015, residential sales are projected to grow at an annual rate of about 1.6 percent, commercial sales at a much higher 2.4 percent rate and industrial sales at only about 1 percent per year.

Table 6 - Continuing Trent (CT) standard case estimate of future electricity sales in Missouri, based on sales trends since 1980-84

Units: Million kWh

	Resid.	Comm.	Indust.	*Total*
1984	18,490	14,576	12,342	***45,408***
1990	21,652	19,335	12,937	***53,925***
1995	25,409	22,493	14,321	***62,222***
2000	27,224	25,825	14,842	***67,891***
2005	29,866	29,230	15,674	***74,770***
2010	32,507	32,636	16,507	***81,650***
2015	35,149	36,042	17,339	***88,529***
Percent increase	*62%*	*86%*	*34%*	***64%***
Growth rate 1984-1995	2.93%	4.02%	1.36%	***0.90%***
Growth rate 1995-2015	1.64%	2.39%	0.96%	***1.78%***

Although the CT projection is proposed as the "high" sales estimate in this study, it may be conservative. In their 1994 and 1995 Integrated Resource Plans (IRPs), AmerenUE forecasted annual sales growth of 1.8 percent through 2005, and Kansas City Power and Light forecasted annual sales growth of 2.3 percent through 2015.[29] The two utilities account for about 57 percent of in-state sales to electricity end users.[30]

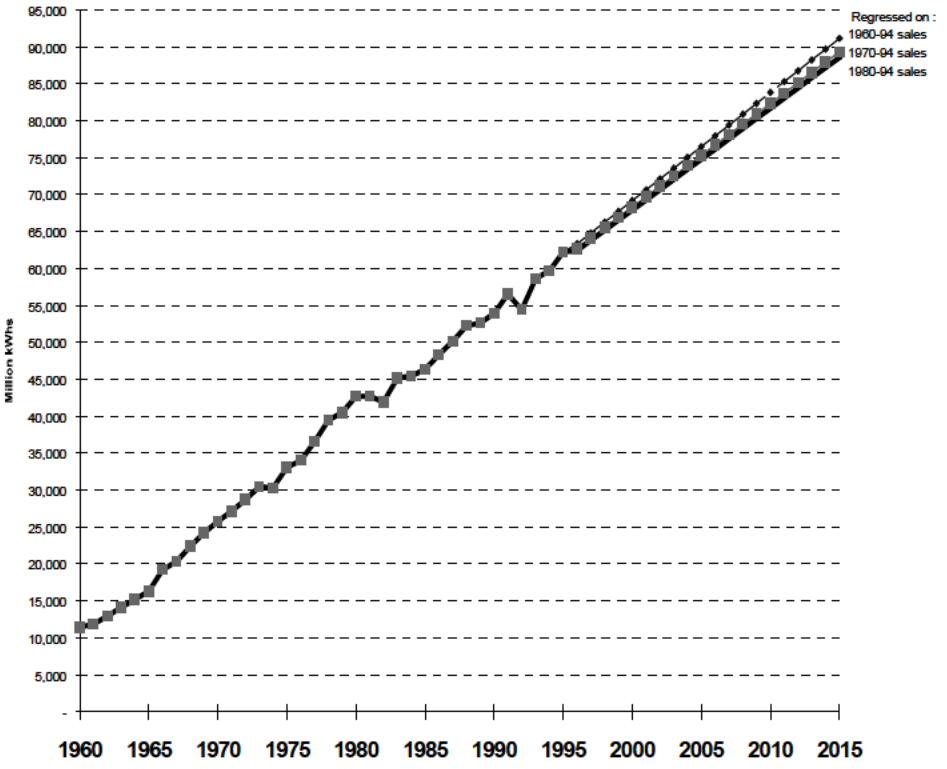
[28] Commercial and industrial sales growth are regressed on the 1984 to 1994 trend because of discontinuities in the USDOE/EIA State Energy Data System (SEDS) database for these sectors between 1980 and 1984. USDOE/EIA, *State Energy Data Report 1994*, p. 398.

[29] AmerenUE, *Energy Resource Plan*, June 1995, p. 15; Kansas City Power and Light (KCPL*), KCPlan 94: Integrated Resource Plan (1995-2014*), Volume 1: Summary, p. III-4.

[30] This estimate is based on analysis of utility-level USDOE/EIA data compiled from reports submitted by Missouri utilities using Form EIA861.

Chart 9 illustrates the CT projections that result from trend analysis based on electricity sales since 1960, 1970 and 1980. Nationally, electricity demand grew at nearly twice the rate of economic growth during the 1960s, slowed in the 1970s to about 1.5 times the rate of economic growth and slowed further in the 1980s to about the same rate as economic growth. Accordingly, the sales trend line based on 1980 to 1994 electricity sales in Missouri is flatter than the other trend lines in Chart 9. A return to sales trends that prevailed in earlier decades would imply higher electricity sales; however, some of this growth was due to the introduction of services and appliances that have since saturated the market.

Chart 9 - Comparison of CT standard and alternative case projections of future Missouri electricity sales



The AEO projections for Missouri electricity sales are extrapolated from AEO regional projections for the residential and commercial sectors and from AEO national projections for the industrial sector. The *Annual Energy Outlook 1997* bases its standard-case projections of national and regional electricity sales on the assumption that future electricity sales will not grow as rapidly in the future as from 1980 to 1994. Therefore, the AEO projection for future electricity sales is lower than the CT projection.

Future electricity sales per person in Missouri's residential and commercial sectors were projected under the assumption that they will grow at the same rate as *Annual Energy Outlook 1997* per capita projections for the North West Central census region, which includes Missouri. Industrial-sector sales were projected under the assumption that they will grow at the same rate as AEO projections for the this region.[31]

Table 7 summarizes the projections for sales in the residential, commercial and industrial sectors and the projected percentage increase with respect to the base year, 1990. The projected 51 percent increase in aggregate sales over the 1990 base year compares to the CT estimate's projection of a 64 percent increase during the same period. Residential sales are projected to grow by 1.1 percent, commercial sales by 1.4 percent, and industrial sales by 1.8 percent between 1995 and 2015.

Table 7 - AEO estimate of future electricity sales in Missouri

Units: Million kWh

	Resid.	**Comm.**	**Indust.**	***Total***
1984	18,490	14,576	12,342	***45,408***
1990	21,652	19,335	12,937	***53,925***
1995	25,409	22,493	14,321	***62,222***
2000	27,605	24,574	16,143	***68,323***
2005	28,475	26,549	17,632	***72,656***
2010	29,805	28,107	19,024	***76,936***
2015	31,650	29,458	20,441	***81,548***
Percent increase	46%	52%	58%	***51%***
Growth rate 1984-1995	2.93%	4.02%	1.36%	***0.90%***
Growth rate 1995-2015	1.10%	1.36%	1.80%	***1.36%***

Per capita electricity use in Missouri's residential and commercial sectors are high relative to the regional average. In 1994, per capita sales of electricity in Missouri's residential sector equaled 4.56 million kWh per person, and, in the commercial sector, 4.08 million kWh per person. Of other states in the North West Central census region, only North Dakota had higher per-capita residential electricity consumption, and only Nebraska had higher per-capita commercial consumption.

[31] North West Central projections of industrial electricity sales growth were used in preference to national projections because the *Annual Energy Outlook 1997* projects that national industrial electricity sales will grow more slowly (1.46 percent) than regional sales (1.80 percent). However, the regional projection could not be adjusted for the differential rate of economic growth because there are no readily available projections of gross regional project (GRP) for census districts. Therefore, the analysis assumes a GSP growth rate of 1.9 percent for Missouri and a GRP growth rate of 1.9 percent for the North West Central region. When the analysis is conducted using the AEO projection for national industrial electricity sales, Missouri sales projections for 2015 are as follows: 20,535 billion kWh assuming high GSP growth; 18,934 billion kWh assuming moderate GSP growth; and 17,244 billion kWh assuming slow GSP growth. The resulting AEO estimate of aggregate in-state electricity sales under moderate growth is 80,041 billion kWh. As stated in the text, the analysis uses a 2.315 percent annual growth rate for high GSP growth, a 1.9 percent rate for moderate growth and a 1.4 percent rate for slow GSP growth.

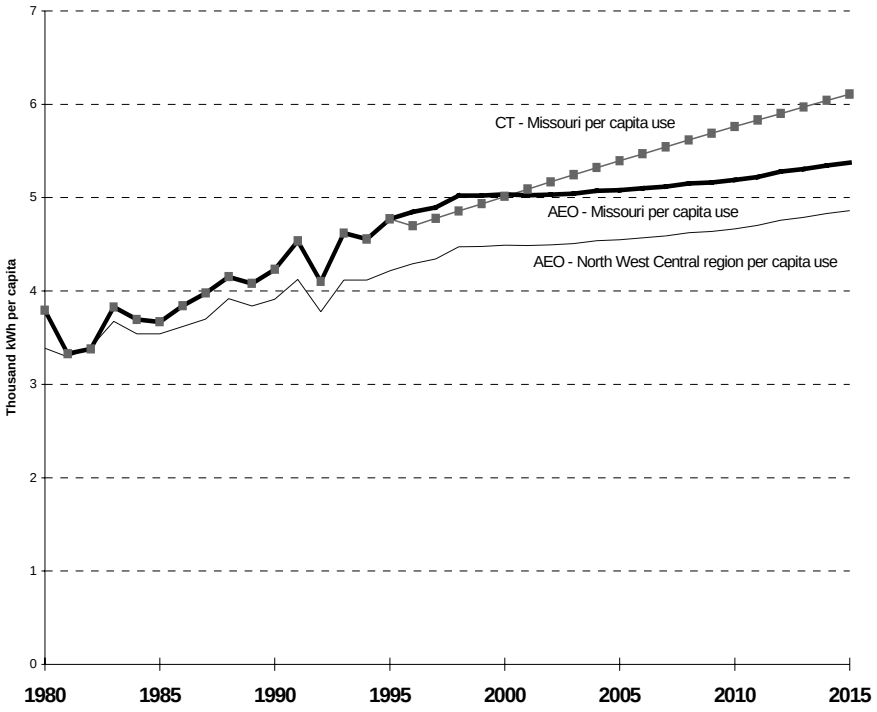
Chart 10 depicts the changes in residential per-capita electricity use implied by the CT and AEO projections for Missouri consumption as well as the AEO projection for the North West Central region as a whole. The AEO analysis projects a distinct flattening of the growth curve, roughly parallel to the regional growth curve. The CT analysis projects continued growth consistent with trends from 1980 to 1994.

As Chart 11 indicates, the AEO analysis projects more substantial growth in commercial per-capita electricity use. However, the growth is slower than the CT projection and flattens over time.

The *Annual Energy Outlook 1997* anticipates that a number of factors will reduce the historic growth rate of residential and commercial electricity demand, including projected lower housing starts and commercial floor-space additions, market saturation of current electric appliances, equipment efficiency improvements including commercial lighting due to technical innovation and legislated standards, and utility investments in demand-side management.

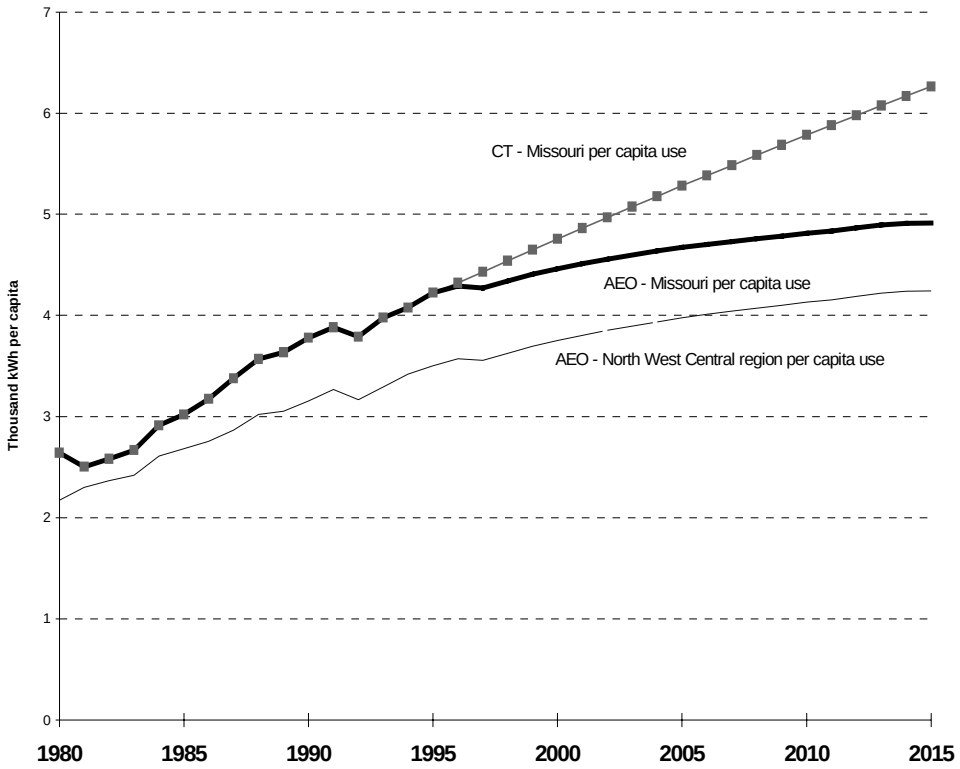
However, the AEO study also cites possible developments that could offset these factors, such as the introduction of new appliances, rapid economic growth and lower electricity prices resulting from market restructuring.[32]

Chart 10 - CT and AEO projections of residential per-capita demand for electricity



[32] *Annual Energy Outlook 1997*, pp. 41, 48, 52-53, 76. Nationally, utility investments in new demand-side management efforts appear to have slowed as attention has shifted to market restructuring.

Chart 11 - CT and AEO projections of commercial per-capita demand for electricity

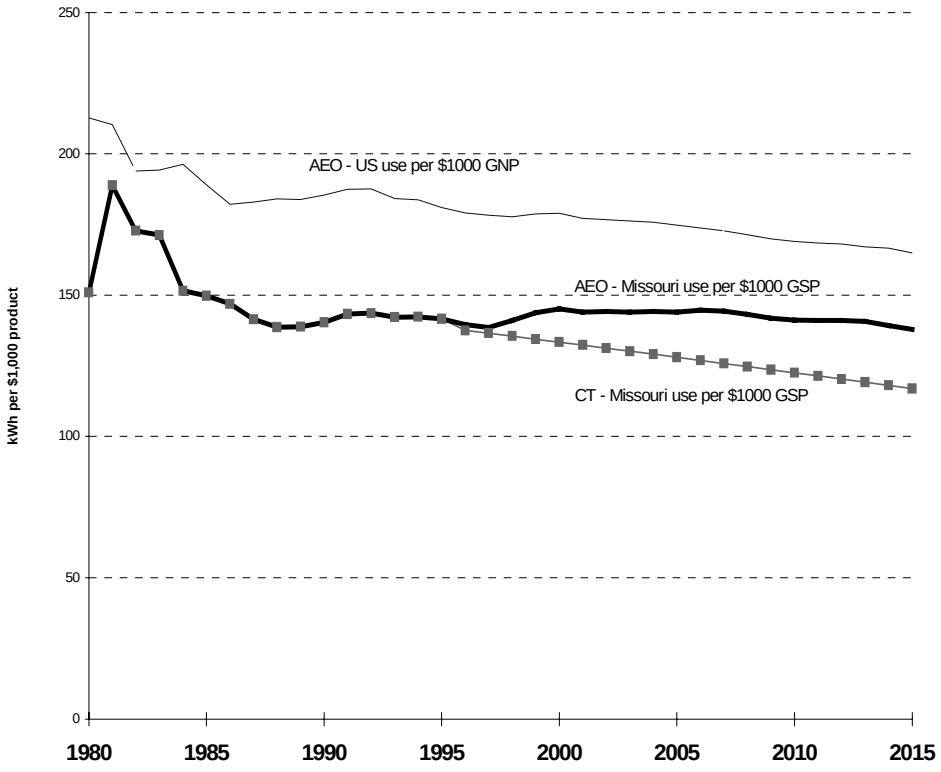


The *Annual Energy Outlook 1997* projects continuing decreases in industrial energy intensity, including use of electricity, because of a combination of efficiency gains and a structural shift toward less energy-intensive industries.[33] The top line in Chart 12 illustrates the projected decline in electricity intensity for industry nationally. The CT projection for Missouri industrial electricity sales, based on past trends, indicates a continued decline in energy intensity roughly parallel to that which the *Annual Energy Outlook 1997* projects for the U.S. However, the AEO extrapolation from North West Central regional projections indicates a flattening of industrial electricity sales per unit of gross state product (GSP) and a growing convergence between Missouri's industrial electricity intensity and that of industry nationally.

[33] *Annual Energy Outlook 1997*, pp. 42, 47.

Missouri's industrial sector is already weighted toward less energy-intensive industry than in the U.S. industry as a whole. Since structural change is one of the components of the USDOE/EIA's forecast, it is reasonable that the drop in energy intensity in Missouri may not be as steep as nationally. It is also possible that, at a state level, the movement of a particular energy-intensive industry into or out of Missouri could strongly influence industry's average energy intensity.

Chart 12 - CT and AEO projections of industrial demand for electricity per unit of Gross State Product



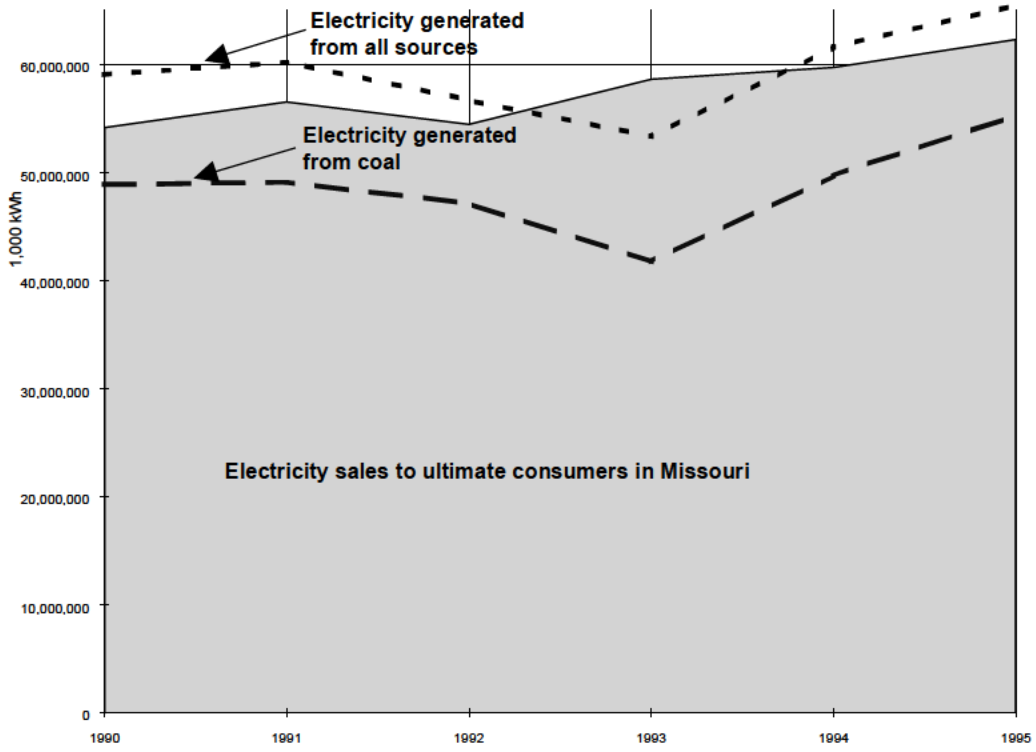
National Electricity sales forecasts from consulting firm Data Resources, Inc./McGraw-Hill are about equal to the *Annual Energy Outlook* forecast, but two other national consulting firms, The WEFA Group (formerly the Wharton Econometric Forecasting Associates) and Gas Research Institute, give somewhat higher forecasts than the *Outlook*.[34] Review of these forecasts suggests it is prudent to construct high and low sales scenarios rather than attempt a single forecast.

[34] *Annual Energy Outlook 1997*, Table 19, p. 79.

Section 2: Estimates of future export sales

In recent years, there has been a near balance between in-state electricity generation and sales in Missouri; about as much electricity is generated in Missouri and sold for consumption within the state. Missouri was a net importer of electricity for several years before 1970 and, with the exception of 1993, has been a net exporter since 1970.[35] Chart 13 depicts the relationship of in-state generation and sales from 1990 to 1995.[36]

Chart 13 - Missouri utility electricity sales and generation, 1990-95



[35] Based on analysis of variables in the USDOE/EIA, SEDS system, Missouri was a net importer for several years before 1970, exported up to 20 percent of in-state sales between 1970 and 1985, and has exported about 5 percent of in-state sales in recent years. Interpretation of the variables is complicated by the fact that several large investor-owned utilities have customers and generating facilities in adjacent states.

[36] The chart provides sales only through 1995 because electricity sales data is not yet available for 1996. In the year 1993, because of impacts of flooding on generating plants, in-state sales exceeded in-state generation, but this is one of only three anomalous years over the past four decades.

The export rate between 1990 and 1996 can be estimated by comparing the total power (million kWh) generated by utilities in Missouri to total sales of electricity (million kWh) to Missouri ultimate consumers, as follows:

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**
Total generated	50,046	60,171	56,661	53,277	61,586	65,442	67,853
Missouri sales	53,925	56,514	54,411	58,622	59,683	62,222	63,384
Export rate	9.5%	6.5%	4.1%	-9.1%	3.2%	5.2%	7.1%

Based on these estimates, a conservative estimate is that Missouri utilities export about 5 percent of the power that they generate in the state each year. The year 1993 must be considered an anomaly. Net electricity imports occurred in 1993 because flooding and a strike by Eastern coal miners reduced the supply of coal to Missouri utilities. Given the extraordinary nature of the 1993 flood and the shift of Missouri utilities from eastern to western suppliers of coal after 1993, these circumstances seem unlikely to recur.

The balance of in-state sales and generation could change under market restructuring and environmental regulations. Under a restructured market system, electricity exports may become more important to Missouri utilities, and electricity imports may become more important to Missouri consumers. Given the relatively low average price of electricity generated in Missouri, restructuring seems more likely to lead to the increased use of coal-fired and other generating capacity in Missouri than to its decreased use or abandonment.[37] On the other hand, NO_x regulations under USEPA's NO_x SIP call may increase the attractiveness of importing power from states not covered by the rule. This could affect utility investment and contract decisions that influence Missouri's electricity export rate.

[37] Average revenue per kilowatt-hour of electricity generated in Missouri in 1994 was 6.28 cents, compared to the U.S. average of 6.91 cents per kilowatt-hour. Prices paid by specific customers or groups of customers vary from average revenue per kilowatt-hour. USDOE/EIA, *Electric Sales and Revenue* 1994.

Section 3: Extent of coal-fired generating capacity in Missouri

Current coal-fired generating capacity in Missouri places an upper limit on short- and intermediate-term CO_2 emissions from coal, due to the relatively long lead time required to construct new facilities. Existing Missouri coal-fired utility plants have substantial unused generating capacity. In 1995, Missouri utilities owned coal-fired steam electric generators capable of generating up to about 78.7 million megawatt-hours of electricity per year, allowing for scheduled maintenance and forced outages.[38] Some unused capacity was soaked up between 1990 and 1996 as electric generation from Missouri coal-fired utility plants increased by about 18 percent, from about 48.5 million to about 57.2 million megawatt-hours. Nevertheless, assuming that a coal plant may generate up to 85 percent of its rated summer capability, actual power generation from Missouri's coal-fired utility plants in 1996 was about 73 percent of potential generation.

In theory, Missouri coal-fired plants could generate an additional 21.5 million megawatt-hours of electricity per year. On the same basis, Missouri coal-fired plants could consume up to 817 trillion Btus of coal,[39] compared to 606 trillion Btus consumed in 1996, and could emit up to 85 million tons of CO_2 compared to 63 million tons in 1996.

The practical limit to Missouri's current coal-fired capacity may be lower than that described above. Several factors could limit current capacity:

- The transmission capability serving some coal-fired plants may limit their practical capacity to less than the theoretical limit.

- Some unused capacity may consist of units where the optimal level of production is less than theoretical capacity and production at theoretical capacity is not economically viable.

- Some unused capacity may consist of inefficient units, which would require upgraded equipment and technology in order to be competitive. Although coal-fired steam plants normally have a long life, up to 65 years, some may be retired before 2015. For example, the National Energy Modeling System (NEMS), on which *Annual Energy Outlook 1997* is based, assumes that plants with total operational costs exceeding 4 cents per kilowatt-hour are marked for retirement.

- A restructured market could increase the incentive to retire inefficient plants or repower them. Depending on the course that restructuring takes, it could either enhance the environment for independent power producers or create barriers. In general, the prospect of restructuring increases the uncertainty of predicting utility and non-utility investment decisions.

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[38] Estimated by multiplying the net summer capability of coal-fired generators (10,575 MW), 6 x 8,760 hours per year, and then by a 0.85 average capacity factor to discount for scheduled maintenance and forced outages.

[39] Estimated by multiplying the theoretical generating capability of Missouri utilities (see Footnote 38), by the calculated average of Missouri coal consumption per mWh (10,500 Btus/mWh). This heat rate is an average for Missouri calculated from Missouri utility data reported on form EIA759 for 1990 to 1996. The utilities reported the quantity of coal burned and power generated from coal. If new coal plants are built, they may have a better heat rate (as low as 9,300 Btus/mWh), but Missouri utilities have not made public any firm plans to build new coal capacity in the state, and such investments are unlikely during the early years of deregulation.

The CO_2 emissions potential of coal-fired plants could be reduced by utility efforts to improve plant generating efficiency, indicated by heat rates. If the generating efficiency of facilities improves, less coal needs to be burned to achieve a given level of generation. Therefore, an improvement in the average heat rate for coal-fired facilities could reduce Missouri utilities' potential coal consumption and CO_2 emissions.

Efforts to improve heat rates are part of normal utility management and will occur. However, based on the reported results of voluntary efforts by some utilities to reduce CO_2 emissions by reducing heat rates, utility efforts to improve heat rates are unlikely to reduce coal consumption and emissions by more than about 1 percent.[40]

The CO_2 emissions potential of coal-fired plants could be increased by future construction. With the prospect of market restructuring increasing the uncertainty facing utilities, they have become reluctant to invest in highly capital-intensive projects such as coal-fired plants. Missouri utilities have no current plans to expand to coal-fired capacity before 2015 and generally have preferred purchasing power under wholesale contract to long-term capital commitments. However, new coal-fired projects are a future possibility if market restructuring results in increasing electricity sales and if, as seems likely, there are reduced opportunities to contract for other utilities' surplus power.

One of the chapter's scenarios for utility CO_2 emissions during 1995 through 2015 includes construction of additional coal-fired generating capacity toward the end of the period. The scenario assumes that Missouri utilities will take advantage of advanced coal technologies that deliver lower heat rates than current Missouri coal-fired plants.[41] The resulting efficiency would result in lower CO_2 emissions than would occur with a less-efficient, coal-fired plant. Nevertheless, because coal has a higher carbon content than natural gas, CO_2 emissions from even a very efficient coal-fired plant will be higher than those from a natural gas turbine.

[40] USEPA, Voluntary Reporting of Greenhouse Gas Emissions, 1996.

[41] USDOE/EIA assumes declining heat rates for new coal technologies averaging 9,463 Btus/kWh for pulverized coal and 7,582 Btus/kWh for advanced coal in 2010. This contrasts with the average heat rate of 10,373 in Missouri coal-fired plants between 1990 and 1996. *Assumptions for the Annual Energy Outlook 1997*, Table 33, p. 58.

Section 4: Specification of the model

Three sets of equations specify the model developed in this chapter:

1) Equations to estimate total CO_2 emissions (E_t) as an aggregate of emissions from coal (E_c), petroleum (E_p), and natural gas (E_n). For each fuel, emissions are estimated by multiplying the quantity consumed by an emissions coefficient (Equations 2-4). To obtain the quantity of natural gas and petroleum, the model uses the values estimated in Part 1, with the CT estimates feeding the high-sales scenarios and the AEO estimates feeding the low-sales scenarios. The quantity of coal burned is an output of the model (Equation 5), based on an estimate of how much power needs to be generated from this source to meet demand.

    1. $E_t = E_c + E_n + E_p$
    2. $E_c = Q_c * C_c$
    3. $E_n = Q_n * C_n$
    4. $E_p = Q_p * C_p$
    5. $Q_c = Gc * 1/Hc$

2) Equations to estimate electricity generated from coal, based on the assumed accounting relationship between net sales (Snet) and generation from coal (G_c) and other sources such as natural gas (G_n) and petroleum (G_p) (Equation 6). Generation from petroleum is estimated based on heat rate (Equation 7). The model uses one of the net sales estimates from Part 2, Section 1, with the CT estimate feeding the high-sales scenarios and the AEO estimate feeding the low-sales scenarios. Net sales is aggregated from sales to the residential, commercial and industrial sectors (Equation 7).

    6. Gc = Snet - (Gn+Gp+Gk+Gh)
    7. Gp = Qp * 1/Hp
    8. Snet = Sr+Sc+Si+Sx

3) An equation to estimate natural gas consumption and power generated from natural gas follows. The equation assumes that total natural gas consumption will be distributed across existing and new technology, following a distribution chart such as the hypothetical chart shown below.

    Gn = Gne + Gno1 + … + Gn
    Gne = Qne * 1/Hne
    Gnb = Qnb * 1/Hnb
    Gno = Qno * 1/Hno
    Qnb = Rnb* Qnn
    Qno = (1-Rnb)* Qnn
    Gp = Qp * 1/Hp

Table 8 presents the hypothetical distribution of natural gas consumption across technologies, which was used for the "HighNG" scenarios and which assume high consumption of natural gas. For the HighNG scenarios, consumption of natural gas reaches 96 trillion Btus in 2015.

Current capacity and planned additions should bring Missouri utilities' total natural gas capacity to about 3,200 megawatts by about 2003. The distribution in Table 8 could be met if utilities add another 500 to 1,000 MW of efficient dual steam capacity and 1,250 MW of combined-cycle capacity coming on line during 2003 through 2015.[42]

Table 8 - Hypothetical distribution of natural gas consumption across technologies for the "high" natural gas scenarios

	Dual Steam	Combined Cycle (1995)	Combined Cycle (1995)	Combined Cycle (2010)	Combined Cycle (2010)
2003	100.0%	0.0%	0.0%		
2004	100.0%	0.0%	0.0%		
2005	40.0%	30.0%	30.0%		
2006	35.0%	32.5%	32.5%		
2007	35.0%	32.5%	32.5%		
2008	30.0%	35.0%	35.0%		
2009	30.0%	35.0%	35.0%		
2010	25.0%	33.9%	33.9%	3.6%	3.6%
2011	20.0%	32.8%	32.8%	7.2%	7.2%
2012	20.0%	29.2%	29.2%	10.8%	10.8%
2013	17.0%	27.1%	27.1%	14.4%	14.4%
2014	14.0%	24.9%	24.9%	18.1%	18.1%
2015	14.0%	23.7%	23.7%	19.3%	19.3%

Table 9 lists and explains the exogenous variables used by the model and those which are determined within the model.

[42] Total capacity was estimated by (1) estimating megawatt-hours generated from each technology type using the heat rates indicated in the distribution table and (2) converting to megawatt capacity assuming 8,760 hours in the year and capacity factors of 6 percent for the pre-2003 steam units, 12-25 percent for the post-2003 steam units and 85 percent for the combined-cycle units.

Table 9 - Variables in the Missouri power generation accounting model

Variable	Description (all quantities assumed to be at state level)	Units	Source and default value
Et	Total CO_2 emissions.	tons	Estimated from model
Ec, En, Ep	CO_2 emissions from coal, natural gas and petroleum.	tons	Estimated from model
Qc	Quantity of coal burned.	Btus	Estimated from model
Qn	Quantity of natural gas burned.	Btus	Given by scenario
Qp	Quantity of petroleum burned.	Btus	Given by scenario
Cc	CO_2 coefficient to determine coal CO_2 emissions from quantity (Btus) of coal:	tons CO_2/Btus	208.7 - USDOE/EIA State Energy Report 1994, Appendix F
Cn	CO_2 coefficient to determine natural gas CO_2 emissions from quantity (Btus) of natural gas:	tons CO_2/Btus	116.4 - Derived from 1990 Inventory
Cp	CO_2 coefficient to determine petroleum CO_2 emissions from quantity (Btus) of petroleum:	tons CO_2/Btus	161.0 - Derived from 1990 Inventory
H_c	Average heat rate for generation from coal. The model could be expanded to include advanced coal technologies by specifying alternative heat rates and the distribution across coal technologies.	Btus/kWh	10.3729 Estimated from 1990 to 1996 EIA759 data for Missouri utilities
H_{n1}	Average heat rates for generation from existing (peaking) natural gas facilities. The inverse converts from generation (kWh) to quantity (Btus) of natural gas.	Btus/kWh	12.8875 Estimated from 1990 to 1996 EIA759 data for Missouri utilities
$H_{n2}…H_{nn}$	Average heat rate for generation from combined cycle natural gas turbines. The inverse converts from generation (kWh) to quantity (Btus) of natural gas. The model could be expanded to include additional advanced natural gas technologies by specifying alternative heat rates and the distribution across gas technologies.	Btus/kWh	6.8000 - USEPA CAPI program
	New dual steam		9.5000
	Combined Cycle 1995		8.0300
	Combined Cycle 2010		7.0000
	Advanced Combined Cycle 1995		6.9850
	Advanced Combined Cycle 2010		5.7000

Variable	Description (all quantities assumed to be at state level)	Units	Source and default value
Hp	Average heat rate for generation from petroleum. The inverse converts from generation (kWh) to quantity (Btus) of petroleum.	Btus/kWh	13.9750 - estimated from 1990-96 EIA759 data for Missouri utilities
Snet	Net sales of electricity.	kWh	Aggregated from individual sources
Sr	Sales to Missouri's residential sector.	kWh	Estimated from historic sales or AEO regional projections using CT or AEO methods
Sc	Sales to Missouri's commercial sector.	kWh	Estimated from historic sales or AEO regional projections using CT or AEO methods
Si	Sales to Missouri's industrial sector.	kWh	Estimated from historic sales or AEO regional projections using CT or AEO methods
St	Sales to Missouri's transportation sector.	kWh	Assumed zero, but may be estimated from historic sales or AEO projections
Sx	Electricity exports.	kWh	Estimated as a percentage of sales to Missouri sectors
Gc,	Electricity generated from coal combustion.	kWh	Estimated from model
G_p	Electricity generated from natural gas, petroleum, nuclear and hydroelectric sources.	kWh	Estimated from scenario-derived quantity of petroleum
Gk, Gh	Electricity generated from nuclear and hydroelectric sources.	kWh	Assumed constant at 1990-96 average
G_{nt}	Total (t) electricity generated from natural gas combustion.	kWh	Aggregated from Gne Gno and Gnb
G_{n1}	Electricity generated from natural gas combustion in "existing" (pre-2003) facilities.	kWh	Estimated based on the proportioning of natural gas use into the three facility types
$G_{n2...}G_{nn}$	Electricity generated from natural gas combustion in new facilities based on technologies "2" through "n."		
Q_{n1}	Quantity of natural gas burned by utilities in existing (pre-2003) facilities.	Btus	Historic data and scenario projections through 2002
Qn2…Qnn	Quantity of natural gas burned by utilities in other facilities.	Btus	Given by scenario

Worksheet 1 shows the model calculations for the two AEO (low sales) scenarios — the high natural gas (HighNG) and low natural gas (LowNG) scenarios. Because of space limitations, several columns that appear in the actual worksheet have been removed from the printed page. The missing columns are those used to account for generation from nuclear, hydroelectric and petroleum sources, and the final columns showing total CO_2 emissions. The worksheet for the high sales scenarios is similar in form and is not shown.

The three leftmost columns in the worksheets are for input estimates of annual electricity sales. Exports are estimated as a percentage of in-state sales. The next set of six unshaded columns is used for the input of low and high estimates of natural gas (NG) energy and the calculation of generation from natural gas and the associated CO_2 emissions. The final set of six shaded columns is used to estimate generation from coal, use of coal and CO_2 emissions. Projected CO_2 emissions are estimated by summing the projected CO_2 emissions from petroleum, natural gas and coal generation.

Worksheet 1 – Model spreadsheet for low sales (AEO) scenario calculations

	In-State Sales (million kWh)	Export Sales (million kWh)	Net Sales (million kWh)	NG Energy (trillion Btus)		NG Generation (million kWh)		Natural Gas CO_2 (1,000 T)		Coal Generation (million kWh)		Coal Energy Use (million kWh)		Coal CO_2 Emissions LowNG / High NG (1,000 T)	
				Low	High	Low	High	Low	High	LowNG	HighNG	LowNG	HighNG		
1990	53,925	10%	59,317	4	4	278	278	207	207	48,854	48,854	502.87	502.87	51,238	51,238
1991	56,514	5%	59,340	13	13	1,000	1,000	746	746	49,070	49,070	499.60	499.60	50,997	50,997
1992	54,411	5%	57,131	2	2	184	184	137	137	47,094	47,094	490.68	490.68	50,124	50,124
1993	58,622	-10%	52,760	5	5	383	383	285	285	41,710	41,710	438.71	438.71	45,284	45,284
1994	59,683	5%	62,668	4	4	338	338	252	252	49,662	49,662	516.23	516.23	53,458	53,458
1995	62,222	5%	65,333	13	13	996	996	743	743	55,280	55,280	568.82	568.82	59,362	59,362
1996	63,384	5%	66,553	5	5	381	381	284	284	57,657	57,657	606.16	606.16	63,453	63,453
1997	63,959	5%	67,157	5	4	366	329	275	247	56,484	56,521	585.90	586.29	61,139	61,179
1998	65,940	5%	69,237	6	9	479	727	359	546	58,453	58,205	606.33	603.75	63,270	63,001
1999	67,191	5%	70,550	9	19	685	1,458	514	1,093	59,563	58,790	617.84	609.82	64,471	63,635
2000	68,323	5%	71,739	9	19	697	1,501	523	1,126	60,742	59,938	630.06	621.73	65,747	64,877
2001	69,019	5%	72,470	9	20	705	1,529	529	1,147	61,467	60,643	637.59	629.04	66,532	65,640
2002	69,928	5%	73,424	10	22	756	1,709	567	1,282	62,372	61,418	646.98	637.08	67,512	66.480
2003	70,807	5%	74,348	10	22	763	1,744	572	1,301	63,290	62,309	656.50	646.32	68,506	67,443
2004	71,831	5%	75,423	11	26	850	2,164	638	1,533	64,280	62,967	666.77	653.14	69,577	68,155
2005	72,656	5%	76,289	13	34	1,023	3,208	768	1,995	64,975	62,790	673.98	651.32	70,329	67,965
2006	73,656	5%	77,338	14	37	1,078	3,533	808	2,139	65,972	63,516	684.32	658.85	71,409	68,751
2007	74,536	5%	78,262	15	40	1,145	3,918	859	2,320	66,830	64,058	693.22	664.46	72,337	69,337
2008	75,375	5%	79,144	16	43	1,216	4,347	912	2,508	67,643	64,512	701.65	669.18	73,217	69,829
2009	76,034	5%	79,836	16	45	1,257	4,580	943	2,616	68,296	64,973	708.43	673.95	73,924	70,327
2010	76,936	5%	80,782	18	50	1,376	5,352	1,032	2,931	69,126	65,150	717.04	675.79	74,823	70,519
2011	77,915	5%	81,811	20	60	1,586	6,709	1,189	3,490	69,947	64,824	725.55	672.41	75,711	70,166
2012	79,102	5%	83,057	21	62	1,631	7,057	1,224	3,611	71,149	65,724	738.02	681.74	77,013	71,140
2013	80,070	5%	84,074	23	70	1,796	8,191	1,347	4,050	72,003	65,609	746.88	680.55	77,937	71,015
2014	80,875	5%	84,919	29	92	2,280	11,395	1,710	5,338	72,366	63,251	750.64	656.09	78,329	68,463
2015	81,548	5%	85,626	31	96	2,375	12,039	1,781	5,589	72,980	63,316	757.02	656.77	78,995	68,534

Section 5: Results of scenario analysis

Two factors distinguish the four "extended" scenarios developed using the procedures in Sections 4: the amount of additional power that Missouri utilities must generate, and the choice between coal and natural gas as the way to supply this additional power.

The choice between coal and natural gas is discussed in Part 1, Section 2 of this chapter. As was indicated in Table 1 at the beginning of this chapter, the four scenarios can be divided into LowNG and HighNG scenarios. The four scenarios can be divided into low-sales and high-sales. For the high-sales scenarios, in-state electricity sales projections were estimated based on simple linear regression from past sales. For low-sales scenarios, in-state electricity sales projections were estimated based on extrapolation from *Annual Energy Outlook 1997* projections. These procedures were described in Part 2, Section 1.

Low sales scenarios: Table 10 summarizes the aggregate CO_2 emissions projected by the two extended scenarios whose in-state electricity sales projections were calculated based on extrapolation from *Annual Energy Outlook 1997* projections. Assuming low natural gas use (LowNG), emissions grow to a maximum of about 81 million tons in 2015, a midrange estimate of emissions. Assuming high natural gas use (HighNG), emissions grow to a maximum of about 75 million tons in 2013 before dropping slightly in 2014 and 2015, a low-emissions estimate.

Table 10 - Estimated CO_2 emissions under AEO (low sales) scenarios

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

Estimated CO_2 emissions	AEO-LowNG	AEO-HighNG
1990	51,540	51,539
1996	63,855	63,854
2000	66,283	66,016
2005	71,110	69,972
2010	75,884	73,479
2015	80,877	74,224

Increase over 1990 baseline	AEO-LowNG	AEO-HighNG
1996	12,316	12,315
2000	14,743	14,477
2005	19,570	18,434
2010	24,344	21,941
2015	29,338	22,686

% increase over 1990 baseline	AEO-LowNG	AEO-HighNG
1996	23.9%	23.9%
2000	28.6%	28.1%
2005	38.0%	35.8%
2010	47.2%	42.6%
2015	56.9%	44.0%

The HighNG scenario projects a 1.5 percent annual growth rate for CO_2 emissions, with only a 4 million ton increase after 2005. Under the HighNG scenario, coal generation and CO_2 emissions stabilize after 2005, and total CO_2 emissions stabilize after 2010.

In contrast, the LowNG scenario projects a 1.8 percent annual growth rate in CO_2 emissions between 1990 and 2015, with more than half the increase in emissions occurring after 2005.

Since the two scenarios use the same estimate of in-state electricity sales, they differ primarily in that utilities under the LowNG scenario continue to generate electricity using the same resource mix that prevailed in 1996, whereas the HighNG scenario is a fuel-switching scenario. Under the HighNG scenario, utilities bring about 1,250 megawatts of base-load natural gas generating capacity into production during the years after 2004, and actually reduce coal consumption during four separate production years, 2004/2005, 2010/2011, 2012/2013 and 2013/2014.

In 2015, under the HighNG scenario, utilities generate more than 12 billion kWh, including some intermediate or base-load power, from natural gas-fired facilities. Under the LowNG scenario, they generate only about 2.4 billion kilowatt-hours of electricity from natural gas in 2015, primarily power used to meet peak demand.

The HighNG introduction of additional power from natural gas reduces total coal generation by 9.7 billion kWh and total CO_2 emissions from coal by 10.5 million tons. Although CO_2 emissions from natural gas increase by 3.8 million tons, net CO_2 emissions are about 6.7 million tons lower under HighNG compared to LowNG.

The results of the HighNG scenario depend on the assumptions about natural gas consumption, heat rates and distribution across technologies specified above. More significantly, the HighNG scenario assumes that utilities would have a reason to stabilize or reduce consumption of coal after 2005.

It is possible that federal legislation penalizing coal use could lead to this result. However, under business-as-usual conditions, this result would occur only if utilities ran into capacity limitations or if the relative price and supply of coal and natural gas changed to the advantage of natural gas. Neither of these situations seems likely. Levels of coal generation under the LowNG scenario appear to be well within the capacity of current coal-fired facilities estimated in Part 2, Section 1. The *Annual Energy Outlook 1997* projects that minemouth prices for western coal, on which Missouri utilities largely depend, will decline by 0.8 percent a year through 2000, then increase by 0.2 percent a year through 2015. Western coal production is projected to grow by 1.4 percent a year.

High Sales Scenarios: Table 11 summarizes the aggregate CO_2 emissions projected by the two CT scenarios. CO_2 emissions under the LowNG scenario grow to about 89 million tons in 2015, a high-CO_2 scenario. The HighNG emissions grow to a maximum of about 82 million tons in 2015, a midlevel CO_2 scenario.

The CT-HighNG scenario projects a 1.9 percent annual growth rate for CO_2 emissions, with only a 3 million ton increase after 2010. Under the HighNG scenario, total CO_2 emissions increase by only 1.3 million tons after 2012.

In contrast, the CT-LowNG scenario projects a 2.2 percent annual growth rate in CO_2 emissions between 1990 and 2015, with a 4.5 million ton increase after 2012.

The LowNG scenario implies an increased utility commitment to coal. Under the scenario, coal consumption climbs steadily, reaching 840 trillion Btus in 2015. The maximum theoretical capacity of Missouri's current coal-fired plants is, at most, about 817 trillion Btus, a level that would be exceeded in 2014. If the practical capacity is lower, the limit would be reached earlier. The LowNG scenario therefore assumes that about 800 megawatts of new coal-fired capacity comes on line by 2011, supplying about 6 billion kWh of total electricity requirements.

In contrast, the HighNG scenario is a mixed-fuel scenario, with the same building of new natural gas capacity that occurs under the AEO HighNG scenario. Under the HighNG scenario, coal consumption increases in all years except 2014 and 2015, but remains well within theoretical capacity. Coal consumption reaches a maximum of 740 trillion Btus in 2013, decreases to 724 trillion Btus in 2014 and increases again to 732 trillion Btus in 2015. Therefore, the construction of new coal-fired plants is not required by this scenario, although the scenario is compatible with the retirement or extensive repowering of old coal plants.

Table 11 - Estimated CO_2 emissions for CT (high sales) scenarios

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

Estimated CO_2 emissions	*CT-LowNG*	*CT-HighNG*
1990	51,539	51,539
1996	63,854	63,854
2000	65,895	65,619
2005	73,660	72,459
2010	81,425	78,893
2015	88,621	82,131

Increase over 1990 baseline	*CT-LowNG*	*CT-HighNG*
1996	12,315	12,315
2000	14,356	14,081
2005	22,121	20,920
2010	29,887	27,355
2015	37,082	30,592

% increase over 1990 baseline	*CT-LowNG*	*CT-HighNG*
1996	23.9%	23.9%
2000	27.9%	27.3%
2005	42.9%	40.6%
2010	58.0%	53.1%
2015	72.0%	59.4%

Section 6: Results of sensitivity analysis

The model developed in this chapter is essentially an accounting model that depends on a number of assumptions and exogenous inputs to generate its results. Each scenario under the model is defined by a combination of two primary factors, the level of electricity sales and level of utility natural gas use. In addition, the model depends on assumptions about coal and natural gas technologies.

The model was specified to be suitable for analyzing the sensitivity of emissions estimates to these factors. Tables 12 and 13 summarize some representative results of this analysis.

Table 12 - Representative results of sensitivity analysis

	Values for Scenario in 2015	Units	Original Scenarios AEO	Original Scenarios CT	Increase In-State Sales by 1% of AEO AEO	Increase In-State Sales by 1% of AEO CT	20% Increase in Export Sales AEO	20% Increase in Export Sales CT
Natural Gas (high)	Total (trillion Btu)	Trillion Btu	96	96	96	96	96	96
In-State Sales	Total (million kWh)	Million kWh	85,626	92,956	86,441	93,771	86,441	93,841
	Sales multiplier		0.0%	0.0%	**1.0%**	**1.0%**	0.0%	0.0%
	Export % of instate		5.0%	5.0%	5.0%	5.0%	**6.0%**	**6.0%**
Heat Rates	New NG	Btu/kWh	9.5000	9.5000	9.5000	9.5000	9.5000	9.5000
	New coal	Btu/kWh	9.4630	9.4630	9.4630	9.4630	9.4630	9.4630
	Old NG	Btu/kWh	12.8875	12.8875	12.8875	12.8875	12.8875	12.8875
	Old Coal	Btu/kWh	10.3729	10.3729	10.3729	10.3729	10.3729	10.3729
LowNG Scenario	CO_2 - total	Thousand tons	80,877	88,621	81,760	89,504	81,760	89,579
	CO_2 - coal	Thousand tons	78,995	87,685	79,877	88,568	79,877	88,643
	CO_2 - natural gas	Thousand tons	1,781	862	1,781	862	1,781	862
	Generated from coal	Million kWh	72,980	81,535	73,796	82,351	73,796	82,421
HighNG scenario	CO_2 - total	Thousand tons	74,224	82,131	75,107	83,013	75,107	83,089
	CO_2 - coal	Thousand tons	68,534	76,468	69,417	77,351	69,417	77,426
	CO_2 - natural gas	Thousand tons	5,589	5,589	5,589	5,589	5,589	5,589
	Generated from coal	Million kWh	63,316	70,646	64,132	71,462	64,132	71,531
CO_2 Growth Rate	Low natural gas		1.82%	2.19%	1.86%	2.23%	1.86%	2.24%
Compared to 1990	High natural gas		1.47%	1.88%	1.52%	1.92%	1.52%	1.93%
CO_2 Change from	Low natural gas	Thousand Tons	0	0	883	883	883	958
Original Scenario	High natural gas	Thousand Tons	0	0	883	883	883	958

Table 13 - Representative results of sensitivity analysis

	Values for Scenario in 2015	Units	12% Increase Nat. Gas High Usage AEO	12% Increase Nat. Gas High Usage CT	1% Decrease Old Coal Heat Rate AEO	1% Decrease Old Coal Heat Rate CT	11% Decrease New Coal Heat Rate AEO	11% Decrease New Coal Heat Rate CT
Natural gas (high)	Total (trillion Btu)	Trillion Btu	**108**	**108**	96	96	96	96
In-State Sales	Total (million kWh)	Million kWh	85,626	92,956	85,626	92,956	85,626	92,956
	Sales multiplier		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Export % of instate		5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Heat Rates	New NG	Btu/kWh	9.5000	9.5000	9.5000	9.5000	9.5000	9.5000
	New coal	Btu/kWh	9.4630	9.4630	9.4630	9.4630	**8.4221**	**8.4221**
	Old NG	Btu/kWh	12.8875	12.8875	12.8875	12.8875	12.8875	12.8875
	Old Coal	Btu/kWh	10.3729	10.3729	**10.2691**	**10.2691**	10.3729	10.3729
LowNG Scenario	CO_2 - total	Thousand tons	80,877	88,621	80,087	87,803	80,877	87,969
	CO_2 - coal	Thousand tons	78,995	87,685	78,205	86,867	78,995	87,033
	CO_2 - natural gas	Thousand tons	1,781	862	1,781	862	1,781	862
	Generated from coal	Million kWh	72,980	81,535	72,980	81,535	72,980	81,535
HighNG Scenario	CO_2 - total	Thousand tons	73,331	81,237	73,539	81,366	74,224	82,131
	CO_2 - coal	Thousand tons	66,970	74,904	67,849	75,703	68,534	76,468
	CO_2 - natural gas	Thousand tons	6,259	6,259	5,589	5,589	5,589	5,589
	Generated from coal	Million kWh	61,872	69,202	63,316	70,646	63,316	70,646
CO_2 Growth Rate	Low natural gas		1.82%	2.19%	1.78%	2.15%	1.82%	2.16%
Compared to 1990	High natural gas		1.42%	1.84%	1.43%	1.84%	1.47%	1.88%
CO_2 Change from	Low natural gas	Thousand tons	0	0	(790)	(818)	0	(652)
Original Scenario	High natural gas	Thousand tons	(893)	(893)	(685)	(765)	0	0

Columns 2-3: Increases in sales

An identical increase in sales leads to the same increase in projected CO_2 emissions under all scenarios. An increase in export sales of electricity has the same effect as an increase in in-state sales. However, since exports are estimated by default as 5 percent of sales, a 20 percent increase in export sales is required to equal a 1 percent increase in in-state sales.

In the AEO scenario, if in-state sales increase by 1 percent, CO_2 emissions in 2015 increase by about 1.2 percent under the HighNG scenario, versus 1.1 percent under the LowNG scenario. A similar differential between "high" and "low" natural gas occurs in the CT scenarios.

This differential is because the scenarios assume all additional sales "at the margin" will be met by increased generation from coal. Since average tons of CO_2 emissions per kilowatt-hour are initially lower for the HighNG scenarios, the incremental emissions from coal have a higher impact on the HighNG average.

Column 4: Increase in natural gas consumption

A 12 percent change in natural gas consumption under the HighNG scenarios has about the same effect as a 1 percent change in sales. The model assumes that an increase in natural gas generation displaces some generation from coal and therefore reduces total emissions.

Columns 5 and 6: Impact of improved heat rates for coal-fired generation

Coal heat rates were discussed in Part 2, Section 2. A 1 percent reduction in the average heat rate for established coal plants might be a realistic target. The effect on CO_2 emissions would be on the same order of magnitude as a 1 percent reduction in sales or a 12 percent increase in natural gas use.

Column 6 tests sensitivity to the construction of a very advanced new coal-fired plant. This is relevant only to the CT-LowNG scenario, which assumes that the new coal-fired plant(s) to be built will have a lower heat rate (9,463 Btus/kWh heat rate) than the average for current coal-fired plants (10,269 Btus/kWh heat rate).

In its 1995 IRP report, AmerenUE considered very advanced technology, advanced pulverized coal with advanced FGD technology, with an estimated heat rate of 8.442 Btus/kWh. Introduction of the new technology at the scale envisioned in the scenario would have about 80 percent of the impact on total utility CO_2 emissions and would lead to a general improvement in the statewide average heat rate for coal.

Part 3: Summary

Table 14 and Table 15 summarize and compare the AEO-direct, CT-direct and extended estimates of utility CO_2 emissions in 2005 and 2015. The tables also indicate, for each estimate, the percentage increase over 1990 baseline emissions.

Table 14 - Direct and extended scenario estimates of Missouri utility CO_2 emissions in 2005

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	AEO direct estimate	CT direct estimate	CT Sales-LowNG	CT Sales-HighNG	AEO Sales-LowNG	AEO Sales-HighNG
Coal	51,238	72,378	64,693	72,940	70,368	70,329	67,965
Natural Gas	207	768	624	624	1,995	768	1,995
Petroleum	93	13	96	96	96	13	13
Total utility emissions	***51,539***	***73,158***	***65,413***	***73,660***	***72,459***	***71,110***	***69,972***
Increase over 1990 baseline							
Coal		41%	26%	42%	37%	37%	33%
Natural Gas		270%	201%	201%	862%	270%	862%
Petroleum		-86%	3%	3%	3%	-86%	-86%
Total		***42%***	***27%***	***43%***	***41%***	***38%***	***36%***

Table 15 - Direct and extended scenario estimates of Missouri utility CO_2 emissions in 2015

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	AEO direct estimate	CT direct estimate	CT Sales-LowNG	CT Sales-HighNG	AEO Sales-LowNG	AEO Sales-HighNG
Coal	51,238	78,584	72,957	87,685	76,468	78,995	68,534
Natural Gas	207	1,781	862	862	5,589	1,781	5,589
Petroleum	93	102	74	74	74	102	102
Total utility emissions	***51,539***	***80,467***	***73,893***	***88,621***	***82,131***	***80,877***	***74,224***
Increase over 1990 baseline							
Coal		53%	42%	71%	49%	54%	34%
Natural Gas		759%	316%	316%	2595%	759%	2595%
Petroleum		9%	-21%	-21%	-21%	9%	9%
Total		***56%***	***43%***	***72%***	***59%***	***57%***	***44%***

For 2005, with one exception,[43] the differences between estimates are not large. By 2015, however, the estimates have separated into fairly distinct low, midrange and high groups. By that year, the percentage increase over baseline 1990 emissions ranges from 72 percent (CT-LowNG scenario) to 43 percent (CT direct estimate and AEO-HighNG scenarios.)

Under the CT-LowNG scenario, coal is the source of more than 99 percent of all utility CO_2 emissions. Even under the AEO-HighNG scenario, it is the source of 93 percent of emissions. The CT-LowNG scenario involves Missouri utilities in an increased commitment to coal, while the AEO-HighNG scenario is a fuel-switching scenario that implies a move away from coal.

In the middle are three midrange estimates that project 80 to 82 million tons of utility CO_2 emissions in 2015; the AEO direct estimate, CT-HighNG and AEO-LowNG scenarios. The CT-HighNG scenario is a mixed-fuel scenario; the AEO-LowNG scenario is a business-as-usual scenario under conditions of relatively slow electricity sales growth.

Even the low-CO_2 scenarios imply that under business-as-usual conditions, Missouri utility CO_2 emissions in 2015 will exceed 1990 baseline emissions by more than 22 million tons. Under the high-CO_2 scenario, utility CO_2 emissions could exceed the baseline by more than 37 million tons.

[43] The CT estimate is an exception for methodological reasons. The CT analysis is based on simple regression analysis. The resulting trend line has a fairly steep slope, but its projections for initial years are unrealistically low.

Greenhouse Gas Emission Trends and Projections for Missouri, 1990-2015 Technical Report

Chapter 4

Projections of CO_2 Emissions from Fossil Fuel Combustion in Missouri End-Use Sectors, 1997-2015

Chapter 4: Projections of CO_2 emissions from fossil fuel combustion in Missouri end-use sectors, 1997-2015

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Chapter 4: Projections of CO_2 emissions from fossil fuel combustion in Missouri end-use sectors, 1997 to 2015

In 1990, Missouri consumers and businesses used about 1,322 trillion Btus of fossil fuel for energy, resulting in about 111.5 million tons of CO_2 emissions. In 1996, Missouri consumers and businesses used about 1,570 trillion Btus of fossil fuel for energy, a 19 percent increase over 1990. Growing at an average annual rate of 3.1 percent, CO_2 emissions increased by about 22.5 million tons to about 134 million tons of CO_2, a 20 percent increase over 1990 emissions.

Under business-as-usual conditions, energy use and CO_2 emissions in Missouri will probably continue growing over the next 20 years, although not as rapidly as between 1990 and 1996. Midrange scenarios developed in this chapter project a 50 million ton increase in energy-based CO_2 emissions between 1990 and 2015, with these emissions totaling about 161 to 163 million tons in 2015. Total greenhouse gas emissions in Missouri are projected to reach between 163 and 180 million tons in 2015; CO_2 emissions from energy will contribute a large and increasing share of that total.

Chapter 2 projected future Missouri utility energy use and CO_2 emissions from fossil fuel combustion through 2015. Table 1 lists historic and projected estimates of utility energy consumption that were developed using estimation methods described in Chapter 2.

Table 1 - Estimates of historic and projected fossil fuel combustion by Missouri utilities in 1990, 1996 and 2015

Units: Trillion Btus

	Total	Natural Gas	Petroleum	Coal
1990	507.6	3.6	1	503
1996	612.5	4.9	1	602
2015 - SS direct	659.3	5.3	2	652
CT direct	714.9	14.8	1	699
CT sales - LowNG	856.0	14.8	1	840
CT sales - HighNG	829.7	96.0	1	733
AEO direct	786.3	30.6	3	753
AEO sales - LowNG	790.2	30.6	3	757
AEO sales - HighNG	755.4	96.0	3	657

The SS direct, CT direct and AEO direct methods are based on estimating CO_2 emissions directly from historic or U.S. Energy Information Administration data, using the Steady State (SS), Continuing Trend (CT) or Annual Energy Outlook (AEO) methods described in Chapter 2. The "AEO sales" methods and "CT sales" methods estimate energy use indirectly, based on electricity sales projections derived using the AEO or CT methods.

Chapter 3 extends these projections to include emissions from Missouri's "end-use" sectors — the transportation, residential, commercial and industrial sectors. Part 1 of this chapter uses the SS, CT and AEO direct methods to project end-use sector energy use through 2015, summarized in Table 2. Part 2 estimates end-use sector CO_2 emissions based on their projected primary fossil fuel energy use.[1] Part 3 estimates the allocation of utility CO_2 emissions to end-use sectors based on their use of electricity.

[1] Strictly speaking, the table estimates primary energy consumption based on fossil fuel *combustion*. At present, nearly all primary energy use of fossil fuels in Missouri is based on combustion, which releases some of the heat content of the fossil fuel as usable energy but also releases CO_2 as a byproduct. In the future, fuel cells will offer an alternative technology for utilizing the energy content of fossil fuels and other energy resources.

Table 2 - Historic and projected fossil fuel combustion in Missouri, by sector and fuel, 1990, 1996 and 2015

Units: Trillion Btus

	1990	1996	SS direct	CT direct	CT sales LowNG	CT sales HighNG	AEO direct	AEO sales LowNG	AEO sales HighNG
Fossil fuel use, by sector and fuel	1322	1565	1814	1819	1960	1934	1896	1905	1870
Energy end-use sectors	814	957	1160	1104	1104	1104	1114	1114	1114
Transportation	472	566	682	752	752	752	687	687	687
Gasoline	332	361	388	435	435	435	378	378	378
Diesel	95	127	182	195	195	195	188	188	188
Jet fuel	38	72	105	115	115	115	106	106	106
Other	7	6	6	6	6	6	15	15	15
Commercial	74	87	95	89	89	89	86	86	86
Natural gas	60	73	79	79	79	79	72	72	72
Petroleum	10	9	12	2	2	2	10	10	10
Coal	4	4	4	8	8	8	3	3	3
Industrial	132	143	207	116	116	116	181	181	181
Natural gas	53	67	97	71	71	71	87	87	87
Petroleum	49	51	74	40	40	40	66	66	66
Coal	30	25	37	5	5	5	28	28	28
Residential	137	161	175	147	147	147	161	161	161
Natural gas	117	137	148	119	119	119	147	147	147
Petroleum	17	22	25	24	24	24	12	12	12
Coal	2	2	2	4	4	4	2	2	2
Utility Sector	508	608	654	715	856	830	782	790	755
Natural gas	4	5	5	15	15	96	31	31	96
Petroleum	1	1	2	1	1	1	3	3	3
Coal	503	602	648	699	840	733	749	757	657

Part 1, Sections 1 to 3 of this chapter discuss the three different methods for estimating future fossil fuel combustion in the end-use sectors — the Steady State (SS), Continuing Trend (CT) and *Annual Energy Outlook* (AEO) methods.

Part 1, Section 4 compares the projections of energy use resulting from these methods. The SS, CT and AEO projections of total end-use sector primary fossil fuel energy consumption tend to converge; for 2015, they estimate that about 80 to 81 million tons of CO_2 emissions will result from fossil fuel combustion in the four sectors. However, the three methods differ in their projections of how this consumption will be distributed across fuels and sectors.

Part 2 estimates CO_2 emissions in Missouri's end-use sectors from fossil fuel combustion, using the estimates of future fossil fuel use developed in Part 1. The estimates are limited to CO_2 emissions from fossil fuel combustion; estimates of CO_2 emissions from other uses of fossil fuels are treated in Chapter 4. All estimates of CO_2 emissions are given in short tons.

The methodology and data sources used to generate the estimates are identical to those described in the *1990 Inventory* and in Chapter 2 of this study. As in Chapter 2, the analysis assumes an economic growth rate of 1.9 percent and relies on projections of Missouri population supplied by the Missouri state demographer and USDOE/EIA.[2] In using carbon content coefficients from these sources, the analysis assumes that the sources and physical characteristics of the fossil fuel consumed will remain stable between 1997 and 2015.

Part 3 presents seven estimates (scenarios) of total state CO_2 emissions from fossil fuel combustion. Each scenario estimate includes two emissions sources — the end-use sectors, whose emissions are estimated in Part 2, and electric utilities, whose emissions are estimated in Chapter 2. The two sources are aggregated by allocating utility CO_2 emissions to the four end-use sectors, based on each end-use sector's share of total electricity use.

The scenarios are adopted from Chapter 2, which introduced scenarios to accommodate uncertainty surrounding future utility energy use. Chapter 2 defined seven methods for estimating utility emissions — three based on the Continuing Trend method, three based on the AEO method, and the seventh based on the Steady State method. Table 3 summarizes the parameters that define the composite scenarios. They are organized into low-, midrange-, and high-emissions scenarios adopted from Chapter 2.

Table 4 summarizes the projections for 2005 and 2015 that result from applying these methods, showing both utility and end-use emissions as well as the aggregate projection. The low-CO_2 scenarios project that total CO_2 emissions from energy use will increase about 42 to 44 million tons between 1990 and 2015, a 38 to 39 percent increase over 1990 emissions. The midrange scenarios project that total CO_2 emissions from energy use will increase about 50 million tons from 1990 to 2015, a 44 to 47 percent increase over 1990 emissions. In these scenarios, end-use CO_2 emissions (that is, emissions from primary fossil fuel use in the end-use sectors) remain larger than utility emissions through the year 2015.

[2] Sources: Missouri Office of Administration, Division of Budgeting and Planning, *Projections of the Population of Missouri Counties by Age, Gender and Race, 1990 to 2020*, May 1994.

Utility emissions are the primary driver that separates the estimates into low-, midrange and high-CO_2 scenarios. In the low-CO_2 scenarios, end-use CO_2 emissions (that is, emissions from primary fossil fuel use in the end-use sectors) are larger than utility emissions through the year 2015. In the midrange- and high-CO_2 scenarios, end-use CO_2 emissions (that is, emissions from primary fossil fuel use in the end-use sectors) are larger than utility emissions through the year 2015.

Table 3 - Summary of parameters defining the high, midrange and low scenarios for CO_2 emissions from fossil fuel combustion

Scenario	Name of Method	How fossil fuel use and CO_2 emissions are estimated for utility sector	How estimated for end-use sectors
Low	SS direct estimate	SS direct estimate (assume that fuel use remains constant per capita or per GSP)	SS direct estimate
	AEO sales – HighNG	Estimate electricity sales based on AEO; estimate coal use based on model	AOE direct estimate
	CT direct estimate	CT direct estimate (linear regression on Missouri utility fuel use trends)	CT direct estimate
Midrange	AEO direct estimate	AEO direct estimate (based on AEO regional projection of utility fuel use)	AEO direct estimate
	AEO sales – LowNG	Estimate electricity sales based on AEO; estimate coal use based on model	AEO direct estimate
	CT sales – HighNG	Estimate electricity sales based on trend; estimate coal use based on model	CT direct estimate
High	CT sales – LowNG	Estimate electricity sales based on trend; estimate coal use based on model	CT direct estimate

Table 4 - Historic and projected Missouri CO_2 emissions from fossil fuel combustion, by scenario, 1990, 1996, 2005 and 2015

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	Scenario	Method	Projected CO_2 emissions			Percent change	
			Utility CO_2 emissions	End-use CO_2 emissions	Total CO_2 emissions	Since 1990	Since 1996
1990			51,539	59,934	111,472		
1996			63,288	70,123	133,411	20%	n/a
2005	**Low**	SS direct estimate	65,910	76,636	142,546	28%	7%
		AEO Sales-HighNG	69,972	76,522	146,494	31%	10%
		CT direct estimate	65,413	73,561	138,974	25%	4%
	Midrange	AEO direct estimate	73,158	76,522	149,681	34%	12%
		AEO Sales-LowNG	71,110	76,522	147,632	32%	11%
		CT Sales-HighNG	72,459	73,561	146,019	31%	9%
	High	CT Sales-LowNG	73,660	73,561	147,221	32%	10%
2015	**Low**	SS direct estimate	68,516	85,050	153,566	38%	15%
		AEO Sales-HighNG	74,224	80,356	154,580	39%	16%
		CT direct estimate	73,893	81,209	155,102	39%	16%
	Midrange	AEO direct estimate	80,467	80,356	160,822	44%	21%
		AEO Sales-LowNG	80,877	80,356	161,233	45%	21%
		CT Sales-HighNG	82,131	81,209	163,339	47%	22%
	High	CT Sales-LowNG	88,621	81,209	169,830	52%	27%

Table 5 summarizes aggregate emissions, by scenario, for 1990, 1996, 2000 and subsequent five-year intervals through 2015. Table 5 also summarizes each interval's average annual growth rate and increase over 1990 emissions. A comparison of the growth rate for a given period to previous and subsequent periods can indicate whether the increase in CO_2 emissions is accelerating or decelerating. These comparisons show that for most scenarios and periods the rate of CO_2 emissions growth is projected to decline.

Table 6, Table 7 and Table 8 summarize the percentage changes and growth rates of the sectors' CO_2 emissions in 2015 compared to 1990. CO_2 emissions from fossil fuel combustion constituted about 75 percent of total greenhouse gas (GHG) source emissions in 1990, but, as Table 6 indicates, the share of Missouri CO_2 emissions deriving from energy use will probably grow to about 83 to 84 percent by 2015.

The average growth rates for energy-based CO_2 emissions that appear in Table 8 are higher than those in Table 5 because they are based on growth since 1990 and therefore include the rapid growth in CO_2 emissions that occurred between 1990 and 1996. The effect of including the 1990 to 1996 period can also be seen by comparing the two rightmost columns in Table 4, one giving average growth rates since 1990 and the other average growth rates since 1996.

Table 9 and Table 10 present four-sector summaries of total state GHG emissions estimates, including a breakdown for each end-use sector into CO_2 emissions from primary fuel use and allocated from utilities. For GHG sources and sinks other than CO_2 emissions from fossil fuel combustion, each of the scenarios in Tables 9 and 10 uses the same estimate.

Table 5 - Projected CO_2 emissions from fossil fuel combustion in Missouri, by scenario, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

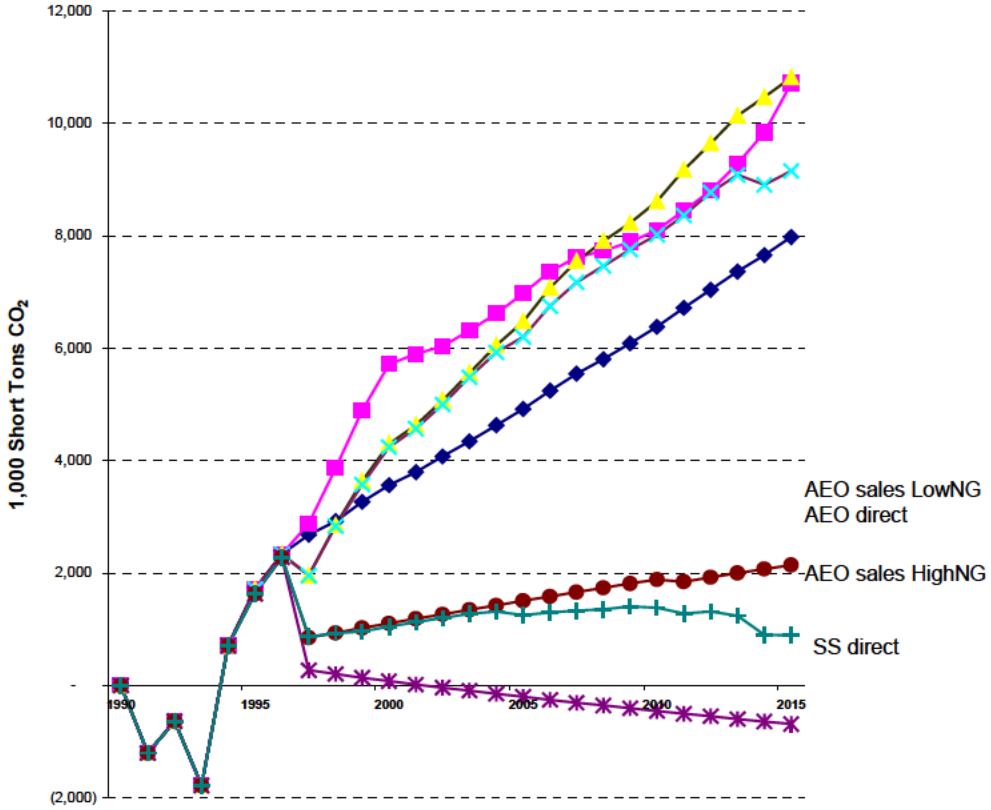

Table 6 - Summary of Missouri greenhouse gas emissions, by scenario, 1990, 1996 and 2015

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1996	CT direct estimate	CT Sales-LowNG	CT Sales-HighNG	AEO direct estimate	AEO Sales-LowNG	AEO Sales-HighNG	SS direct estimate
Net greenhouse gas emissions	120,996	141,893	165,945	180,672	174,182	171,503	171,914	165,261	164,352
Fossil fuel CO_2 including electricity	111,472	133,411	155,102	169,830	163,339	160,822	161,233	154,580	153,566
Transportation	36,782	44,208	58,842	58,842	58,842	52,250	52,250	52,250	53,303
Commercial	23,104	29,089	36,275	42,391	39,696	34,408	34,556	32,153	32,208
Industrial	22,649	24,927	21,962	24,794	23,546	33,371	33,474	31,807	30,630
Residential	28,937	35,187	38,023	43,803	41,255	40,793	40,952	38,370	37,425
Other sources	36,598	34,215	33,345	33,345	33,345	33,183	33,183	33,183	33,288
Fossil energy as % of source	75%	80%	82%	84%	83%	83%	83%	82%	82%

Table 7 - Percent increase of Missouri greenhouse gas emissions, by scenario, 1996 and 2015 compared to 1990

	1990	1996	CT direct estimate	CT Sales-LowNG	CT Sales-HighNG	AEO direct estimate	AEO Sales-LowNG	AEO Sales-HighNG	SS direct estimate
Net greenhouse gas emissions		17%	37%	49%	44%	42%	42%	37%	36%
Fossil fuel CO_2 including electricity		20%	39%	52%	47%	44%	45%	39%	38%
Transportation		20%	60%	60%	60%	42%	42%	42%	45%
Commercial		26%	57%	83%	72%	49%	50%	39%	39%
Industrial		10%	-3%	9%	4%	47%	48%	40%	35%
Residential		22%	31%	51%	43%	41%	42%	33%	29%
Other sources		-7%	-9%	-9%	-9%	-9%	-9%	-9%	-9%

Table 8 - Rate of growth of Missouri greenhouse gas emissions, by scenario, 1996 and 2015 compared to 1990

	1990	1996	CT direct estimate	CT Sales-LowNG	CT Sales-HighNG	AEO direct estimate	AEO Sales-LowNG	AEO Sales-HighNG	SS direct estimate
Net greenhouse gas emissions		2.7%	1.3%	1.6%	1.5%	1.4%	1.4%	1.3%	1.2%
Fossil fuel CO_2 including electricity		3.0%	1.3%	1.7%	1.5%	1.5%	1.5%	1.3%	1.3%
Transportation		3.1%	1.9%	1.9%	1.9%	1.4%	1.4%	1.4%	1.5%
Commercial		3.9%	1.8%	2.5%	2.2%	1.6%	1.6%	1.3%	1.3%
Industrial		1.6%	-0.1%	0.4%	0.2%	1.6%	1.6%	1.4%	1.2%
Residential		3.3%	1.1%	1.7%	1.4%	1.4%	1.4%	1.1%	1.0%
Other sources		-1.1%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%	-0.4%

Table 9 - Summary projections of Missouri greenhouse gas emissions, by scenario, 2005

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1996	CT direct estimate	CT Sales-LowNG	CT Sales-HighNG	AEO direct estimate	AEO Sales-LowNG	AEO Sales-HighNG	SS direct estimate
Net greenhouse gas emissions	120,996	141,893	147,228	155,474	154,273	157,932	155,884	154,746	150,783
Greenhouse gas sources	148,071	167,626	171,368	179,614	178,413	182,073	180,024	178,886	174,924
Carbon dioxide emissions	123,129	145,289	151,578	159,824	158,623	162,282	160,234	159,096	155,133
CO_2 from fossil fuel combustion	111,472	133,411	138,974	147,221	146,019	149,681	147,632	146,494	142,546
Transportation	36,782	44,208	50,326	50,326	50,326	49,821	49,821	49,821	48,183
Gasoline	25,826	28,044	30,646	30,646	30,646	29,305	29,305	29,305	29,037
Diesel	7,578	10,131	12,421	12,421	12,421	12,461	12,461	12,461	12,035
Jet	2,971	5,672	6,897	6,897	6,897	7,398	7,398	7,398	6,738
Other	408	360	362	362	362	658	658	658	373
Commercial	23,104	29,089	31,282	34,554	34,078	32,055	31,306	30,891	30,587
Electricity	18,479	23,625	25,956	29,228	28,751	26,733	25,984	25,568	24,925
Nat. Gas	3,494	4,258	4,251	4,251	4,251	4,179	4,179	4,179	4,409
Petroleum	721	881	438	438	438	810	810	810	906
Coal	410	325	637	637	637	334	334	334	346
Industrial	22,649	24,927	22,444	24,153	23,904	29,626	29,129	28,853	27,570
Electricity	12,365	14,314	13,553	15,262	15,013	17,754	17,256	16,980	14,906
Nat. Gas	3,077	3,921	3,838	3,838	3,838	4,623	4,623	4,623	4,658
Petroleum	4,107	4,127	3,474	3,474	3,474	4,594	4,594	4,594	4,903
Coal	3,100	2,564	1,579	1,579	1,579	2,655	2,655	2,655	3,104
Residential	28,937	35,187	34,921	38,187	37,711	38,178	37,376	36,930	36,206
Electricity	20,694	25,349	25,904	29,170	28,694	28,672	27,870	27,424	26,079
Nat. Gas	6,822	7,986	7,108	7,108	7,108	8,225	8,225	8,225	8,269
Petroleum	1,200	1,680	1,565	1,565	1,565	1,099	1,099	1,099	1,672
Coal	221	173	344	344	344	182	182	182	187
Other sources of CO_2	11,656	11,878	12,604	12,604	12,604	12,602	12,602	12,602	12,588
Methane emissions	16,527	17,876	15,460	15,460	15,460	15,460	15,460	15,460	15,460
Nitrous oxide emissions	3,805	3,820	3,872	3,872	3,872	3,872	3,872	3,872	3,872
PFC emissions	4,611	641	458	458	458	458	458	458	458
CO_2 sequestration from forest growth	(27,074)	(25,732)	(24,140)	(24,140)	(24,140)	(24,140)	(24,140)	(24,140)	(24,140)

Table 10 - Summary projections of Missouri greenhouse gas emissions, by scenario, 2015

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1996	CT direct estimate	CT Sales-LowNG	CT Sales-HighNG	AEO direct estimate	AEO Sales-LowNG	AEO Sales-HighNG	SS direct estimate
Net greenhouse gas emissions	120,996	141,893	165,945	180,672	174,182	171,503	171,914	165,261	164,352
Greenhouse gas sources	148,071	167,626	188,448	203,175	196,685	194,006	194,416	187,763	186,854
Carbon dioxide emissions	123,129	145,289	168,575	183,302	176,812	174,133	174,543	167,890	166,981
CO_2 from fossil fuel combustion	111,472	133,411	155,102	169,830	163,339	160,822	161,233	154,580	153,566
Transportation	36,782	44,208	58,842	58,842	58,842	52,250	52,250	52,250	53,303
Gasoline	25,826	28,044	33,831	33,831	33,831	29,332	29,332	29,332	30,186
Diesel	7,578	10,131	15,595	15,595	15,595	13,612	13,612	13,612	14,572
Jet	2,971	5,672	9,052	9,052	9,052	8,398	8,398	8,398	8,158
Other	408	360	365	365	365	908	908	908	388
Commercial	23,104	29,089	36,275	42,391	39,696	34,408	34,556	32,153	32,208
Electricity	18,479	23,625	30,685	36,801	34,106	29,067	29,215	26,812	26,322
Nat. Gas	3,494	4,258	4,620	4,620	4,620	4,214	4,214	4,214	4,583
Petroleum	721	881	127	127	127	784	784	784	942
Coal	410	325	843	843	843	343	343	343	360
Industrial	22,649	24,927	21,962	24,794	23,546	33,371	33,474	31,807	30,630
Electricity	12,365	14,314	14,208	17,040	15,792	20,170	20,273	18,605	15,297
Nat. Gas	3,077	3,921	4,103	4,103	4,103	5,091	5,091	5,091	5,640
Petroleum	4,107	4,127	3,118	3,118	3,118	5,272	5,272	5,272	5,936
Coal	3,100	2,564	533	533	533	2,839	2,839	2,839	3,758
Residential	28,937	35,187	38,023	43,803	41,255	40,793	40,952	38,370	37,425
Electricity	20,694	25,349	29,000	34,780	32,233	31,230	31,389	28,807	26,897
Nat. Gas	6,822	7,986	6,927	6,927	6,927	8,558	8,558	8,558	8,596
Petroleum	1,200	1,680	1,640	1,640	1,640	814	814	814	1,738
Coal	221	173	455	455	455	191	191	191	194
Other sources of CO_2	11,656	11,878	13,472	13,472	13,472	13,310	13,310	13,310	13,415
Methane emissions	16,527	17,876	15,589	15,589	15,589	15,589	15,589	15,589	15,589
Nitrous oxide emissions	3,805	3,820	3,868	3,868	3,868	3,868	3,868	3,868	3,868
PFC emissions	4,611	641	416	416	416	416	416	416	416
CO_2 sequestration from forest growth	(27,074)	(25,732)	(22,503)	(22,503)	(22,503)	(22,503)	(22,503)	(22,503)	(22,503)

Part 1: Estimates of future fossil fuel combustion in Missouri's transportation, residential, commercial and industrial sectors

Sections 1 through 3 describe three methods for projecting fossil fuel use in Missouri end-use sectors — the transportation, residential, industrial and commercial sectors. Section 4 compares the differences in the scenarios' projections for different fuels and sectors. Section 5 estimates emissions for each fuel in each sector, aggregates these estimates by sector and extends the utility emissions scenario analysis developed in Chapter 4 to include end-use sector emissions.

The three methods, introduced in Chapter 2, are as follows:

- the Steady State (SS) scenario, which assumes that use of Missouri fossil fuel per person or per unit of Gross State Product (GSP) will remain constant from 1996 through 2015;

- the Continuing Trend (CT) scenario, which assumes that Missouri fossil fuel use will continue to increase or decrease between 1996 and 2015 as it has in the recent past; and

- the AEO scenario, which assumes that changes in Missouri's fossil fuel use will mirror those that are projected nationally or regionally by the USDOE Energy Information Administration (EIA) in its *Annual Energy Outlook 1997*.

Section 1: Steady State method

The Steady State (SS) method estimates future fossil fuel use *assuming that current patterns of energy use continue into the future*. The method assumes that, through the year 2015, Missouri citizens and businesses will continue to use energy resources as they do now. More specifically, projections of energy use under the steady state method assume that fuel use per capita or per unit of gross state product (GSP) will remain constant at 1996 levels through 2015.

In the simple form in which it is developed here, the only energy data used by the SS method for its projections are current (1996) consumption numbers. Thus, the projection incorporates no information about past changes in energy use. It also does not project the impact of factors such as changes in economic activity or structure, demographic shifts, technological change or the development or exhaustion of energy resources. Because the SS method does not incorporate such factors, its value is primarily to provide perspective for interpreting other methods rather than for stand-alone projection of state energy use.

The primary assumptions of the SS method are as follows:

- For the industrial sector and for certain transportation fuels (diesel and jet fuel), fuel use per unit of GSP will remain constant at 1996 levels through 2015. Thus, future consumption of these fuels is assumed to grow at the projected growth rate of GSP.[3] Missouri GSP is expected to grow at a rate of about 1.9 percent through 2015.

- For other transportation fuels and other sectors, fuel use per capita will remain constant at 1996 levels through 2015. Thus, future consumption is assumed to grow at the projected growth rate of state population. Missouri population is expected to grow at a rate of about 0.4 percent through 2015.[4]

The assumption that utility fuel use will increase at the rate of population growth implies slower growth in utility fossil fuel use compared to the growth that occurred between 1990 and 1996 or compared to the average growth of all fuel consumption. Utility fossil fuel use increased by 21 percent between 1990 and 1996, a six-year span. According to the SS method projection, by 2015 utility fossil fuel use will increase to only 30 percent of 1990 usage, while total fossil fuel use in 2015 by all Missouri sectors will be about 38 percent greater than in 1990.

Table 11 summarizes the assumptions used to project fossil fuel combustion in the different sectors.

Table 11 - Steady State method to project end-use sector fossil fuel combustion

Sector	Item Projected	Assumptions
Residential and commercial	All fossil fuel use	Constant energy use per capita
Industrial	All fossil fuel use	Constant energy use per unit of GSP
Transportation	Use of diesel and jet fuel	Grows at projected growth rate of Missouri GSP
Transportation	Use of gasoline and other fuels	Grows at projected growth rate of Missouri Population

Table 12 summarizes the SS method's projections of fossil fuel combustion by sector, and the three subsequent tables summarize the method's projections for use of coal, petroleum and natural gas. Under the SS method, fossil fuel energy use is projected to increase from about 1.32 trillion Btus in 1990 to about 1.82 trillion Btus in 2015.

[3] Estimate by Business and Public Administration Research Center, University of Missouri - Columbia.

[4] Projections of Missouri population developed by the Missouri state demographer are used throughout the study. The zero migration model was used, and population estimates were adjusted using an "adder," which adjusted projected state population to actual population in 1995.

Table 12 - Steady State method projections of fossil fuel combustion in Missouri

Units: Trillion Btus

	1990	1996	2005	2010	2015	Change from base
Fossil fuel combustion	1,321.7	1,568.6	1,683.2	1,748.2	1,814.0	37%
Energy end-use sectors	814.1	960.6	1,053.6	1,106.3	1,159.5	42%
Transportation	471.5	565.5	622.9	653.4	682.5	45%
Gasoline	332.4	360.9	373.7	381.0	388.5	17%
Diesel	94.9	126.9	150.7	165.8	182.5	92%
Jet fuel	37.6	71.8	92.4	100.4	105.2	179%
Other	6.6	5.9	6.1	6.2	6.4	-4%
Commercial	73.6	88.0	91.1	92.9	94.7	29%
Natural gas	60.0	73.2	75.8	77.2	78.8	31%
Petroleum	9.5	11.6	11.9	12.2	12.4	31%
Coal	4.0	3.2	3.4	3.5	3.5	-13%
Industrial	132.2	143.8	171.3	188.5	207.5	57%
Natural gas	52.9	67.4	80.0	88.1	96.9	83%
Petroleum	48.9	51.3	60.9	67.0	73.7	51%
Coal	30.4	25.1	30.4	33.4	36.8	21%
Residential	136.8	163.3	168.2	171.5	174.9	28%
Natural gas	117.2	137.2	142.1	144.8	147.7	26%
Petroleum	17.4	24.4	24.3	24.8	25.3	45%
Coal	2.2	1.7	1.8	1.9	1.9	-12%
Electric utility sector	507.6	608.1	629.6	641.9	654.5	29%
Natural gas	3.6	4.9	5.1	5.2	5.3	48%
Petroleum	1.2	1.4	1.5	1.5	1.6	34%
Coal	502.9	601.7	623.0	635.2	647.7	29%

Table 13 - Coal combustion under the Steady State method, showing each sector's share of coal use

Units: Trillion Btus

	1990	1996	2005	2010	2015
Commercial	4	3	3	3	4
Industrial	30	25	30	33	37
Residential	2	2	2	2	2
Utility	503	602	623	635	648
Total coal use	539	632	659	674	690
Total for end-use sectors	***37***	***30***	***36***	***39***	***42***
Increase over 1990					
Commercial		-21.1%	-15.9%	-14.3%	-12.6%
Industrial		-17.3%	0.1%	10.1%	21.2%
Residential		-22.0%	-15.8%	-14.1%	-12.4%
Utility		19.7%	23.9%	26.3%	28.8%
End-use sectors		***-18.0%***	***-2.6%***	***6.0%***	***15.4%***

Table 14 - Petroleum combustion under the Steady State method, showing each sector's share of petroleum use

Units: Trillion Btus

	1990	1996	2005	2010	2015
Transportation	466	561	618	648	677
Gasoline	332	361	374	381	388
Diesel	95	127	151	166	182
Jet fuel	38	72	92	100	105
Other	1	1	1	1	1
Commercial	10	12	12	12	12
Industrial	49	51	61	67	74
Residential	17	24	24	25	25
Utility	1	1	1	2	2
Total petroleum use	543	649	717	754	790
End-use sectors	***542***	***648***	***715***	***752***	***789***
Increase over 1990					
Transportation		20.3%	32.6%	39.1%	45.3%
Gasoline		8.6%	12.4%	14.6%	16.9%
Diesel		33.7%	58.8%	74.8%	92.3%
Jet fuel		90.9%	145.6%	166.7%	179.5%
Other		-14.3%	-11.2%	-9.5%	-7.7%
Commercial		22.3%	25.8%	28.2%	30.7%
Industrial		4.8%	24.5%	37.0%	50.8%
Residential		40.0%	39.4%	42.1%	44.9%
Utility		24.1%	28.5%	31.0%	33.6%
End-use sectors		***19.6%***	***31.9%***	***38.8%***	***45.5%***

Table 15 - Natural gas combustion under the Steady State method, showing each sector's share of natural gas use

Units: Trillion Btus

	1990	1996	2005	2010	2015
Transportation	5	5	5	5	5
Commercial	60	73	76	77	79
Industrial	53	67	80	88	97
Residential	117	137	142	145	148
Utility	4	5	5	5	5
Total natural gas use	239	287	308	320	334
End-use sectors	***235***	***283***	***303***	***315***	***329***

Increase over 1990	**1990**	**1996**	**2005**	**2010**	**2015**
Transportation		-10.4%	-7.2%	-5.4%	-3.5%
Commercial		21.9%	26.2%	28.7%	31.2%
Industrial		27.4%	51.4%	66.6%	83.3%
Residential		17.1%	21.2%	23.6%	26.0%
Utility		37.1%	42.0%	44.7%	47.6%
End-use sectors		***20.0%***	***28.6%***	***33.9%***	***39.5%***

Section 2: Continuing Trend method

The Continuing Trend (CT) method estimates CO_2 emissions from fossil fuel *assuming that recent trends in Missouri's energy use continue into the future*. This method relies on projecting future energy use from past energy consumption data. Thus the CT method's projections make use of more energy data than those of the SS method and implicitly incorporate the past influence of economic, demographic and technological factors. However, the CT method does not incorporate information about how these factors might change in the future. Implicitly, it assumes that future energy use will be determined by the same factors that have determined past energy use.

The CT method uses simple linear regression to project past energy use trends into the future.[5] For the end-use sectors, the regression analysis was based on trends from 1982 to the most recent data available. Although data previous to 1982 was available, it was not incorporated into the regression analysis because from 1974 to 1982 there were unique disturbances to energy supply and demand. Use of data from these years would probably have distorted the results of the trend analysis. Chapter 2 describes the CT methods used for the utility sector projections.

Table 16 summarizes the CT method's projections of fossil fuel combustion by sector, and the three subsequent tables summarize the method's projections for use of coal, petroleum and natural gas. Fossil fuel energy use is projected to increase from about 1.32 trillion Btus in 1990 to about 1.82 trillion Btus in 2015.

[5] ORIMA methods would have been more suitable but the statistical tools were not available for this project. One consequence of using regression is that, in many cases the dependent value for 1996 emissions estimated by least-square regression is less than the historic value, whereas the SS and AEO estimates assume the historic value for 1996 emissions as a beginning point. Therefore, although the CT projection captures a great deal of information from previous years, it is probably more meaningful for intermediate than short-term projections.

Table 16 - Continuing Trend method projections of fossil fuel combustion in Missouri

Units: Trillion Btus

	1990	1995	2005	2010	2015	Change from base
Fossil fuel use	1,322	1,497	1,634	1,726	1,819	38%
Energy end-use sectors	814	914	1,002	1,052	1,104	36%
Transportation	472	542	643	697	752	59%
Gasoline - tran	332	352	394	414	435	31%
Diesel - tran	95	118	156	175	195	106%
Jet fuel - tran	38	66	87	101	115	205%
Other transportation fuels	7	6	6	6	6	-6%
Commercial	74	80	85	87	89	21%
Nat. gas - comm	60	65	73	76	79	32%
Petroleum - comm	10	11	6	4	2	-82%
Coal - comm	4	3	6	7	8	104%
Industrial	132	142	125	120	116	-12%
Nat. gas - indust	53	66	66	68	71	33%
Petroleum - indust	49	50	44	42	40	-18%
Coal - indust	30	25	15	10	5	-83%
Residential	137	150	148	148	147	8%
Nat. gas - res	117	125	122	121	119	2%
Petroleum - res	17	23	23	23	24	37%
Coal - res	2	2	3	4	4	105%
Electric utility sector	508	583	632	673	715	41%
Nat. gas - utility	4	13	11	13	15	314%
Petroleum- utility	1	2	1	1	1	-21%
Coal - utility	503	569	620	660	699	39%

Table 17 - Coal combustion under the Continuing Trend method, showing each sector's share of coal use

Units: Trillion Btus

	1990	1995	2005	2010	2015
Commercial	4	3	6	7	8
Industrial	30	25	15	10	5
Residential	2	2	3	4	4
Utility	503	569	620	660	699
Total coal use	539	599	645	681	717
Total for end-use sectors	***37***	***30***	***25***	***22***	***18***
Increase over 1990					
Commercial		-19.3%	54.7%	79.6%	104.5%
Industrial		-16.5%	-49.1%	-66.0%	-82.8%
Residential		-18.7%	55.1%	80.1%	105.0%
Utility		13.1%	23.3%	31.2%	39.0%
End use sectors		***11.1%***	***19.6%***	***26.3%***	***32.9%***

Table 18 - Petroleum combustion under the Continuing Trend method, showing each sector's share of petroleum use

Units: Trillion Btus

	1990	1995	2005	2010	2015
Transportation	466	537	638	691	746
Gasoline	332	352	394	414	435
Diesel	95	118	156	175	195
Jet fuel	38	66	87	101	115
Other	1	1	1	1	0
Commercial	10	11	6	4	2
Industrial	49	50	44	42	40
Residential	17	23	23	23	24
Utility	1	2	1	1	1
Total petroleum use	543	624	711	761	812
End-use sectors	***542***	***622***	***710***	***760***	***811***

Increase over 1990				
Transportation	15.2%	36.9%	48.3%	60.0%
Gasoline	6.0%	18.7%	24.7%	31.0%
Diesel	24.4%	63.9%	84.9%	105.8%
Jet fuel	75.2%	132.2%	168.4%	204.7%
Other	-11.3%	-40.8%	-55.5%	-70.2%
Commercial	20.8%	-39.2%	-60.8%	-82.3%
Industrial	2.5%	-10.8%	-14.4%	-17.9%
Residential	34.4%	30.5%	33.6%	36.8%
Utility	47.6%	2.4%	-9.5%	-21.5%
End-use sectors	***14.8%***	***31.0%***	***40.3%***	***49.7%***

Table 19 - Natural gas combustion under the Continuing Trend method, showing each sector's share of natural gas use

Units: Trillion Btus

	1990	1995	2005	2010	2015
Transportation	5	5	5	6	6
Commercial	60	65	73	76	79
Industrial	53	66	66	68	71
Residential	117	125	122	121	119
Utility	4	13	11	13	15
Total natural gas use	239	274	277	283	290
End-use sectors	***235***	***261***	***266***	***271***	***275***

Increase over 1990	**1990**	**1996**	**2005**	**2010**	**2015**
Transportation		-11.4%	-1.1%	4.1%	9.2%
Commercial		8.4%	21.7%	26.9%	32.2%
Industrial		25.6%	24.7%	29.0%	33.3%
Residential		6.7%	4.2%	2.9%	1.5%
Utility		258.2%	199.3%	256.5%	313.7%

Section 3: Annual Energy Outlook method

The AEO method assumes Missouri's future energy consumption will mirror the energy use projections contained in the USDOE Energy Information Administration's *Annual Energy Outlook 1997*. The *Annual Energy Outlook*, published each year, is based on EIA's National Energy Modeling System (NEMS). NEMS provides national and regional-level business-as-usual estimates of energy use that explicitly incorporate assumptions about future economic, demographic and technological change. The AEO method, unlike the CT method, incorporates information about how these factors might change in the future.

Because NEMS generates only national and regional energy projections, it is necessary to extrapolate state-level projections for Missouri. For most sectors and fuels, the extrapolation is based on AEO projections of per-capita energy use in a two-region area, the North West Central and North East Central regions.[6] For fossil fuels in the industrial sector and certain fuels in the transportation sector that are primarily freight-oriented, the extrapolation is based on AEO projections of national energy use per unit of Gross National Product (GNP).[7]

For each sector and fuel, the following method was used to extrapolate annual projections of energy use:

1. Estimated energy consumption per capita is calculated from EIA regional energy use projections, or estimated energy consumption per unit of GNP is calculated from national energy use projections, depending on the sector and fuel. For example, population was used to extrapolate energy use in the residential and commercial sectors, and gross product was used to extrapolate energy use in the industrial sector.

2. A theoretical estimate of state energy consumption was calculated by multiplying regional energy consumption per capita by the projected state population or by multiplying national energy consumption per unit of GNP by the projected state GSP.

3. An "adder" was calculated to adjust the initial estimate in the series to equal the best estimate of Missouri energy consumption in that year. The same adder was then used to adjust subsequent state energy consumption estimates.

Unlike the SS and CT methods, the AEO method can generate non-linear projections of future energy use based on assumptions about changes in the factors that affect energy use. For example, the curvilinear path of AEO gasoline use projections depicted in Chart 1, on page 37, are curved rather than linear.

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[6] Missouri is included in the North West Central Region and borders the North East Central region. Missouri borders two additional regions, the West South Central and East South Central. The study uses a 2-region instead of a 4-region average because the two southern regions are energy-producing regions and therefore dissimilar to Missouri.

[7] An extrapolation based on energy use per unit of regional gross product could not be used because no data series for regional gross product is available.

The AEO projections incorporate the projections of expected advances in end use technologies including shell and equipment efficiencies. The projections are gathered from industry experts including utilities and manufacturers.

Table 20 summarizes the AEO method's projections of fossil fuel combustion by sector, and the three subsequent tables summarize the method's projections for use of coal, petroleum and natural gas. Fossil fuel energy use is projected to increase from about 1.32 trillion Btus in 1990 to about 1.86 trillion Btus in 2015.

Table 20 - *Annual Energy Outlook* method projections of fossil fuel combustion in Missouri

Units: Trillion Btus

	1990	1996	2005	2010	2015	Change from base
Fossil fuel use	1,321.7	1,568.6	1,778.5	1,835.9	1,961.6	48%
Energy end-use sectors	814.1	960.6	1,054.4	1,091.2	1,114.3	37%
Transportation	471.5	565.5	647.1	674.2	686.5	46%
Gasoline - tran	332.4	360.9	377.2	379.8	377.5	14%
Diesel - tran	94.9	126.9	165.5	179.4	187.9	98%
Jet fuel - tran	37.6	71.8	93.7	101.6	106.4	183%
Other transportation fuels	6.6	5.9	10.7	13.3	14.8	122%
Commercial	73.6	88.0	85.8	85.9	86.1	17%
Nat. gas - comm	60.0	73.2	71.8	72.0	72.4	21%
Petroleum - comm	9.5	11.6	10.7	10.5	10.3	9%
Coal - comm	4.0	3.2	3.3	3.3	3.4	-17%
Industrial	132.2	143.8	162.4	171.5	180.9	37%
Nat. gas - indust	52.9	67.4	79.4	84.2	87.5	65%
Petroleum - indust	48.9	51.3	57.0	60.8	65.7	34%
Coal - indust	30.4	25.1	26.0	26.5	27.8	-8%
Residential	136.8	163.3	159.1	159.6	160.7	17%
Nat. gas - res	117.2	137.2	141.3	144.2	147.0	25%
Petroleum - res	17.4	24.4	16.0	13.6	11.8	-32%
Coal - res	2.2	1.7	1.8	1.8	1.9	-14%
Electric utility sector	507.6	608.1	724.1	744.7	847.3	67%
Nat. gas - utility	3.6	4.9	34.3	50.4	96.0	2581%
Petroleum- utility	1.2	1.4	0.7	1.6	2.6	125%
Coal - utility	502.9	601.7	689.2	692.7	748.6	49%

The following three tables summarize AEO projections of coal, petroleum and natural gas combustion in Missouri through 2015.

Table 21 - Coal combustion under the *Annual Energy Outlook* method, showing each sector's share of coal use

Units: Trillion Btus

	1990	1996	2005	2010	2015
Commercial	4	3	3	3	3
Industrial	30	25	26	27	28
Residential	2	2	2	2	2
Utility	503	602	689	693	749
Total coal use	539	632	720	724	782
Total for end-use sectors	37	30	31	32	33
Increase over 1990					
Commercial		-21.1%	-19.0%	-17.8%	-16.7%
Industrial		-17.3%	-14.4%	-12.7%	-8.5%
Residential		-22.0%	-18.1%	-15.9%	-13.8%
Utility		19.7%	37.0%	37.8%	48.9%
End-use sectors		***17.1%***	***33.5%***	***34.3%***	***44.9%***

Table 22 - Petroleum combustion under the *Annual Energy Outlook* method, showing each sector's share of petroleum use

Units: Trillion Btus

	1990	1995	2005	2010	2015
Transportation	466	561	639	665	676
Gasoline	332	361	377	380	378
Diesel	95	127	165	179	188
Jet fuel	38	72	94	102	106
Other	1	1	3	4	4
Commercial	10	12	11	11	10
Industrial	49	51	57	61	66
Residential	17	24	16	14	12
Utility	1	1	1	2	3
Total petroleum use	543	650	723	751	766
End-use sectors	***542***	***648***	***723***	***750***	***764***
Increase over 1990					
Transportation		20.3%	37.1%	42.6%	45.0%
Gasoline		8.6%	13.5%	14.3%	13.6%
Diesel		33.7%	74.4%	89.1%	98.0%
Jet fuel		90.9%	149.0%	170.1%	182.7%
Other		-12.9%	105.1%	190.1%	234.1%
Commercial		22.3%	12.4%	10.7%	8.8%
Industrial		4.8%	16.5%	24.3%	34.2%
Residential		40.0%	-8.4%	-21.8%	-32.1%
Utility		24.1%	-40.7%	35.4%	124.7%
End-use sectors		***19.6%***	***33.3%***	***38.3%***	***40.9%***

Table 23 - Natural gas combustion under the *Annual Energy Outlook* method, showing each sector's share of natural gas use

Units: Trillion Btus

	1990	1995	2005	2010	2015
Transportation	5	5	8	10	10
Commercial	60	73	72	72	72
Industrial	53	67	79	84	87
Residential	117	137	141	144	147
Utility	4	5	34	50	96
Total natural gas use	239	287	335	360	413
End-use sectors	***235***	***283***	***301***	***310***	***317***

Increase over 1990	**1990**	**1996**	**2005**	**2010**	**2015**
Transportation		-11.1%	51.3%	78.9%	95.7%
Commercial		21.9%	19.6%	20.0%	20.6%
Industrial		27.4%	50.2%	59.3%	65.4%
Residential		17.1%	20.6%	23.0%	25.4%
Utility		37.1%	856.9%	1306.3%	2581.2%

Section 4: Comparison of the AEO and CT estimates of future fossil fuel combustion in Missouri end-use sectors

The CT and AEO scenarios project nearly identical increases in total primary fossil fuel use in the end-use sectors between 1990 and 2015. The CT scenarios project a 36 percent increase over 1990 consumption, and the AEO scenarios project a 37 percent increase.[8]

Despite the similarity in the projected total emissions, the CT and AEO scenarios diverge in their projections for specific sectors and fuels. The differences flow from the different methods used to estimate future consumption. Under the CT method, future consumption is determined primarily by the growth trend of the sector or fuel over the previous 10 to 12 years. Under the AEO method, it may be determined by a variety of assumptions about the influence of future economic, demographic and technological factors on energy use.

The most striking divergence between the scenarios occurs in projecting primary fossil fuel use in the transportation and utility sectors. Through 2015, the AEO scenarios project annual growth rates of 1.5 percent for transportation fossil fuel use and 1.3 percent for industrial use. The CT scenarios project a faster 1.9 percent growth rate for consumption of fossil fuels in the transportation sector and a negative 0.5 percent growth rate for consumption in the industrial sector.

Table 24 summarizes the CT and AEO scenarios' projections of average annual growth rates of primary fossil fuel use in the transportation, commercial, industrial and residential sectors between 1990 and 2015.

[8] The SS scenario projects a 42 percent increase, larger than that from the CT and AEO scenarios. However, this section focuses on the CT and AEO scenarios. Under the SS method, the increase in consumption of a specific fuel is determined primarily by whether consumption is assumed to grow at the state population growth rate or the state GSP growth rate. The method is included primarily for comparison; it uses less information than the other two methods, and some of its projections lack credibility.

Table 24 - Average annual growth rates of primary fossil fuel use in the end-use sectors, for the CT and AEO methods, 1990-2015

	CT average annual growth rate				AEO average annual growth rate			
	1990-1996	1996-2005	2005-2015	1990-2015	1990-1996	1996-2005	2005-2015	1990-2015
Transportation	3.1%	1.4%	1.6%	1.9%	3.1%	1.5%	0.6%	1.5%
Gasoline	1.4%	1.0%	1.0%	1.1%	1.4%	0.5%	0.0%	0.5%
Diesel	5.0%	2.3%	2.3%	2.9%	5.0%	3.0%	1.3%	2.8%
Jet fuel	11.4%	2.2%	2.8%	4.6%	11.4%	3.0%	1.3%	4.2%
Other	-1.9%	0.3%	0.3%	-0.3%	-1.9%	6.9%	3.2%	3.2%
Commercial	2.8%	-0.3%	0.5%	0.8%	2.8%	-0.2%	0.0%	0.6%
Natural gas	3.4%	0.0%	0.8%	1.1%	3.4%	-0.2%	0.1%	0.8%
Petroleum	-0.1%	-5.3%	-11.6%	-6.7%	-0.1%	1.4%	-0.3%	0.3%
Coal	1.6%	3.9%	2.8%	2.9%	1.6%	-3.3%	0.3%	-0.7%
Industrial	1.4%	-1.5%	-0.8%	-0.5%	1.4%	1.4%	1.1%	1.3%
Natural gas	4.1%	-0.2%	0.7%	1.2%	4.1%	1.8%	1.0%	2.0%
Petroleum	0.8%	-1.8%	-0.8%	-0.8%	0.8%	1.2%	1.4%	1.2%
Coal	-3.4%	-5.1%	-10.3%	-6.8%	-3.4%	0.6%	0.7%	-0.4%
Residential	2.8%	-0.9%	-0.1%	0.3%	2.8%	-0.2%	0.1%	0.6%
Natural gas	2.7%	-1.3%	-0.3%	0.1%	2.7%	0.3%	0.4%	0.9%
Petroleum	3.8%	0.5%	0.5%	1.3%	3.8%	-3.4%	-3.0%	-1.5%
Coal	1.6%	3.9%	2.8%	2.9%	1.6%	-3.2%	0.5%	-0.6%

Transportation fossil fuel combustion

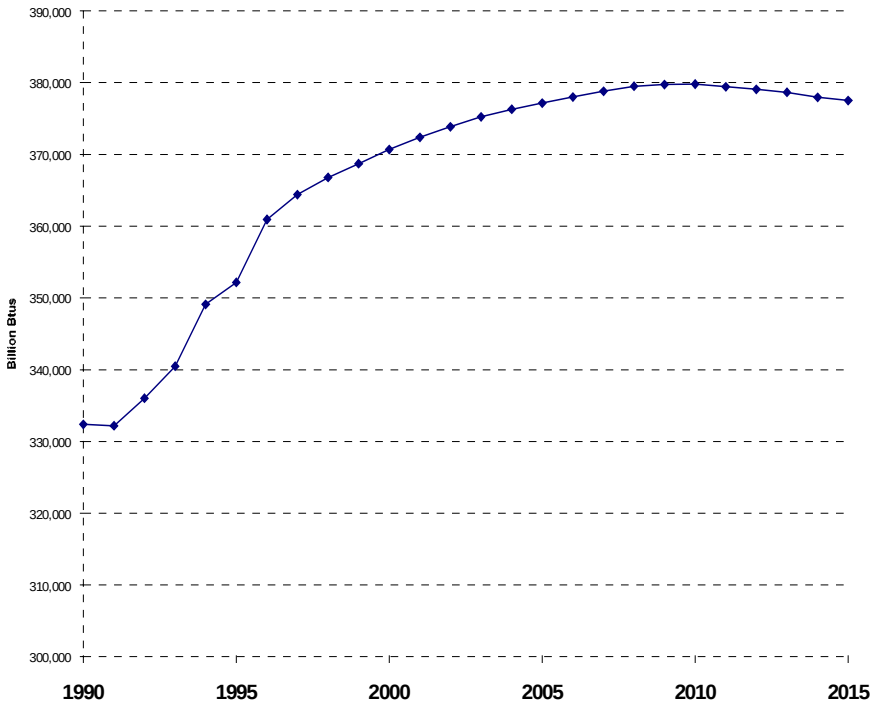
In 1990, use of motor gasoline, primarily for personal vehicles, accounted for about 71 percent of total fossil fuel use in Missouri's transportation sector. The AEO and CT scenarios project that between 1990 and 2015, diesel and jet fuel will become more prominent in the total mix of transportation fuel use.

The CT scenarios anticipate that motor gasoline use will continue to increase at an average annual growth rate of 1 percent. Nevertheless, these scenarios anticipate that gasoline's share will decline to about 58 percent of the total transportation mix because diesel and jet fuel use will increase at a higher growth rate than gasoline use. Diesel fuel's share will increase from about 20 percent to 26 percent, and jet fuel's share will increase from about 8 percent to 15 percent. [9]

The AEO scenarios, which are based on the USDOE/EIA *Annual Energy Outlook 1997*, anticipate that the growth rate of motor gasoline use will decrease after 1996 and that motor gasoline consumption will decline after 2010. Chart 1 illustrates the AEO projection for gasoline use through 2015.

[9] The projections for Missouri jet fuel use are based on simple regression of trend (CT method) or AEO regional projections. They may underestimate the future rate of growth of jet fuel use in Missouri because they do not take into account the planned expansion of Lambert-St. Louis International Airport. Lambert is the sixth busiest commercial airport in the United States. In September, 1998, the Federal Aviation Administration issued a favorable Record of Decision for Lambert's expansion, as described in a press release posted at http://www.lambert-stlouis.com/expansion.html

Chart 1 - Projected gasoline use in Missouri, based on* Annual Energy Outlook 1997 *regional projection, 1990-2015



The AEO scenarios anticipate that gasoline's share will decline to about 55 percent of the total transportation mix. Diesel fuel's share will increase from about 20 percent to 27 percent, and jet fuel's share will nearly double from about 8 percent to 16 percent.

By 2015, transportation fossil fuel use under the CT scenarios is projected to increase to 60 percent over the level in 1990, versus 46 percent under the AEO scenarios. As Table 24 indicates, the AEO and CT scenarios project nearly identical growth in total transportation fuel use between 1996 and 2005, but diverge sharply between 2005 and 2015.

Under the AEO scenarios, gasoline use does not grow between 2005 and 2015, and growth in diesel and jet fuel use slows from a 3.0 percent annual growth rate to a 1.3 percent annual rate. Under the CT scenarios, gasoline use continues to grow at 1 percent per year, diesel use continues to grow at a 2.3 percent annual rates, and the growth rate of jet fuel use increases from 2.3 percent to 2.8 percent by 2015.

USDOE/EIA projections of gasoline use for transportation are based on economic factors such as price and income as well as legislative mandates and a number of demographic, sociological and technological factors. Factors expected to lead to a decrease in the growth rate for gasoline use include:

(1) A decrease in the growth rate for personal income. The *Annual Energy Outlook 1997* (AEO97) projected that personal income would grow at about 1.9 percent per annum compared to rates between 2.5 and 3.0 percent during previous decades.
(2) An increase in the average age of the driving population. National Personal Transportation Survey (NPTS) data indicate that as people grow older, they drive less. Although "Baby Boomers" may drive more after retirement than previous generations, they are still expected to drive less than during their working years.
(3) One factor previously influencing increases in motor gasoline use was the increase in average Vehicle Miles Traveled (VMT) by women as they entered the work force. This will not be as much a factor in the future as the influx of women into the work force slows and as female VMT approaches male VMT.
(4) Continued gains in vehicle efficiency. In assessing efficiency, EIA takes into account new technologies that are on the horizon such as electric hybrid vehicles and direct injection gasoline vehicles, as well as technologies such as fuel cells that are likely to be introduced later. However, gains are expected to continue but to occur at a slower pace than in the 1980s, in part due to increasing popularity of sport utility vehicles, light trucks and high-horsepower vehicles, which are less efficient than sedans or station wagons.
(5) Greater use of alternative fuel vehicles, including vehicles in commercial fleets.

EIA has revised its analysis since *AOE97* was published. EIA projections for transportation gasoline consumption in the *Annual Energy Outlook* for 1998 *(AEO98)* and 1999 (*AEO99)* are higher than the *AEO97* projections used in this study, and EIA no longer projects an absolute decline in gasoline use after 2010. The *AEO97* national reference case projects a 0.8 percent growth rate for motor gasoline use between 1995-2015; the *AEO98* national reference case projects a 1.3 percent growth rate between the same years. The *AEO99* estimate for the growth in gasoline use will be somewhere in the middle. [10]

[10] *AEO97*, Table A-2; *AEO98*, Table A-2; and personal communication, David Chien, EIA, 9/3/98. The *AEO99* analysis has not been completed and this discussion of its findings is therefore subject to revision.

The most important factors in this revision are economic, particularly fuel price, which affects both fuel consumption and decisions on new vehicle purchase. *AEO98* and *AEO99* project lower gasoline prices than *AEO97* and put greater emphasis on the increasing popularity of sport utility vehicles, light trucks and high-horsepower vehicles. In addition, *AEO98* and *AEO99* project higher growth in personal income than *AEO97,* albeit below the personal income growth rate of previous decades.

Industrial fossil fuel combustion

The industrial sector, unlike Missouri's other energy use sectors, uses a nearly even mix of fuels — approximately 40 percent petroleum, 30 percent natural gas and 30 percent coal in 1990. Primary fossil fuel use in the industrial sector increased at a 1.4 percent average annual growth rate between 1990 and 1996; natural gas use grew at a 4.1 percent annual rate, while coal use declined. However, the CT scenarios project that industrial primary fossil fuel use in 2015 will be lower than total use in 1990, that coal and petroleum use will decline below 1990 levels and that natural gas use will be at approximately the same level as in 1996.

The CT projection reflects post-1980 energy use trends in Missouri's industrial sector; coal use has declined sharply, petroleum use has declined moderately[11] and natural gas use has fluctuated.[11]

In contrast, the AEO scenarios project a 34 percent increase in industrial fossil fuel use, with increases in both natural gas and petroleum use. The *Annual Energy Outlook 1997* cites projections for plentiful supply and stable price as factors leading to growth in natural gas consumption. The *Annual Energy Outlook 1997* also cites technological and structural changes that may reduce industrial energy use, but their impact will be primarily on electricity use.

The SS scenarios project an even larger, 69 percent, increase in industrial fossil fuel use. However, this is a somewhat artificial result that follows from the methodological assumption that industrial fuel consumption will grow at the rate of gross state product.

[11] The downward trend in the projection of petroleum use is partly due to a downward adjustment in USDOE/EIA estimates for industrial petroleum use between 1990 and 1991. See Chapter 2, page 28, Methodological Note 1.

Residential and commercial fossil fuel consumption

With respect to CO_2 emissions, the chief role of the residential and commercial sectors is as consumers of electricity. The two sectors also accounted for about 75 percent of Missouri's natural gas consumption in 1990. However, Table 45, illustrates that electricity use in these sectors is a more important contributor to CO_2 emissions than primary fossil fuel use.

Primary fossil fuel consumption in both sectors achieved a rapid average annual growth rate of 2.8 percent between 1990 and 1996 due to growth of natural gas use in both sectors and growth of petroleum use in the residential sector. However, the AEO and CT scenarios agree that there will be minimal growth in primary fossil fuel consumption in the two sectors between 1996 and 2015.

The *Annual Energy Outlook 1997* cites several factors reducing energy use in the commercial sector. In addition to projected slow growth of commercial floor space, the *Annual Energy Outlook* cites areas in which technological improvements are expected, including the efficiency of building shells and of furnaces, boilers and heat pumps fired by natural gas or distillate oil. The *Annual Energy Outlook* anticipates similar technological improvements in the residential sector.

CT scenario projections for total fuel use in the residential and commercial sectors are quite similar to AEO scenario projections. The only point of divergence is over the projected fuel mix in the residential sector.

The *Annual Energy Outlook 1997* projects that residential natural gas use will increase due to declining natural gas prices, larger homes and increased use of natural gas heat pumps — although this increase will be moderated by increased heating efficiency per residential square foot due to building code requirements for new construction. The *Annual Energy Outlook* further projects that CO_2 emissions from petroleum and coal use will decrease as residential energy users switch to natural gas or electricity and projects that the share of natural gas in the residential fossil fuel mix will increase from 86 to 92 percent between 1990 and 2015.

In contrast, the CT scenarios, on the basis of earlier trends, projects continued reduction in natural gas consumption and very modest growth in residential petroleum and coal consumption. Accordingly, the CT scenarios anticipate that the share of natural gas in the residential fossil fuel mix will decrease from 86 to 81 percent between 1990 and 2015.

Mix and distribution of coal, petroleum and natural gas use

In 1990, utilities consumed 93 percent of the ***coal*** used in Missouri, and the industrial sector consumed nearly 6 percent. From 1990 to 1996, utility consumption increased and industry consumption declined so that in 1996 their shares were 95 percent and 4 percent. The AEO and SS methods project that this distribution will remain constant through 2015, but the CT method projects that industrial coal use, continuing past trends, will decline to less than a 1 percent share by 2015.

In 1990, the transportation sector consumed 86 percent of the ***petroleum*** used in Missouri, and about 61 percent of all petroleum consumption was for gasoline. All three methods project that petroleum will continue to be used predominantly for transportation and that gasoline's share of total petroleum use will decrease as the shares of diesel and jet fuel increase. However, the CT and SS methods anticipate a faster transfer of share from gasoline to diesel than does the AEO method.

In 1990, the residential, commercial and industrial sectors consumed 96 percent of the ***natural gas*** used in Missouri; the residential sector alone consumed 49 percent. All CT and AEO scenarios project more even distribution of natural gas use in 2015.

The standard CT scenario projects that the residential share will fall to 41 percent, with a modest increase in the shares of the commercial, industrial and utility sectors. The standard AEO scenario projects that both the residential and commercial sectors will lose shares to the industrial and utility sectors.

The AEO and CT "HighNG" scenarios project a more radical shift in which the utility sector becomes the second most important user of natural gas, accounting for nearly 30 percent of total natural gas consumption in 2015.

The AEO "HighNG" scenario also projects a shift in the total fossil fuel mix, with the share of natural gas increasing from about 18 to 21 percent between 1990 and 2015 and the share of petroleum decreasing from about 41 to 39 percent. The shift is primarily the result of decelerating growth in gasoline use and increasing utility consumption of natural gas.

The following tables summarize primary fossil fuel use projections for Missouri's end-use sectors. Table 25 summarizes the three methods' projections of Missouri fossil fuel combustion through 2015, and Table 26 summarizes percentage changes from consumption in the 1990 baseline year.

Table 25 - Estimated historic (1990, 1996) and projected (2005, 2015) fossil fuel combustion in Missouri, by sector

Units: Trillion Btus

	1990	1996	2005 SS	2005 CT	2005 AOE	2015 SS	2015 CT	2015 AEO
Use (trillion Btus) by sector and fuel	1,322	1,565	1,683	1,634	1,757	1,814	1,819	1,896
Energy end-use sectors	814	957	1,054	1,002	1,054	1,160	1,104	1,114
Transportation	472	566	623	643	647	682	752	687
Gasoline	332	361	374	394	377	388	435	378
Diesel	95	127	151	156	165	182	195	188
Jet fuel	38	72	92	87	94	105	115	106
Other	7	6	6	6	11	6	6	15
Commercial	74	87	91	85	86	95	89	86
Natural gas	60	73	76	73	72	79	79	72
Petroleum	10	9	12	6	11	12	2	10
Coal	4	4	3	6	3	4	8	3
Industrial	132	143	171	125	162	207	116	181
Natural gas	53	67	80	66	79	97	71	87
Petroleum	49	51	61	44	57	74	40	66
Coal	30	25	30	15	26	37	5	28
Residential	137	161	168	148	159	175	147	161
Natural gas	117	137	142	122	141	148	119	147
Petroleum	17	22	24	23	16	25	24	12
Coal	2	2	2	3	2	2	4	2
Electric utility sector	508	608	630	632	703	654	715	782
Use (trillion Btus) by fuel and sector	1,322	1,565	1,683	1,634	1,757	1,814	1,819	1,896
Coal	539	633	659	645	720	690	717	782
Commercial	4	4	3	6	3	4	8	3
Industrial	30	25	30	15	26	37	5	28
Residential	2	2	2	3	2	2	4	2
Utility	503	602	623	620	689	648	699	749
Petroleum	543	645	717	711	723	790	812	766
Transportation	466	561	618	638	639	677	746	676
Commercial	10	9	12	6	11	12	2	10
Industrial	49	51	61	44	57	74	40	66
Residential	17	22	24	23	16	25	24	12
Utility	1	1	1	1	1	2	1	3
Natural Gas	239	287	308	277	314	334	290	348
Transportation	5	5	5	5	8	5	6	10
Commercial	60	73	76	73	72	79	79	72
Industrial	53	67	80	66	79	97	71	87
Residential	117	137	142	122	141	148	119	147
Utility	4	5	5	11	13	5	15	31

Table 26 - Projected percentage change in Missouri fossil fuel combustion, by method, compared to 1990 baseline

	1990	1996	2005 SS	2005 CT	2005 AOE	2015 SS	2015 CT	2015 AEO
Fossil fuel use, by sector and fuel	0.0%	18.4%	27.3%	23.6%	33.0%	37.2%	37.6%	43.5%
Energy end-use sectors	0.0%	17.6%	29.4%	23.0%	29.5%	42.4%	35.6%	36.9%
Transportation	0.0%	19.9%	32.1%	36.4%	37.2%	44.7%	59.4%	45.6%
Gasoline - tran	0.0%	8.6%	12.4%	18.7%	13.5%	16.9%	31.0%	13.6%
Diesel - tran	0.0%	33.7%	58.8%	63.9%	74.4%	92.3%	105.8%	98.0%
Jet fuel - tran	0.0%	90.9%	145.6%	132.2%	149.0%	179.5%	204.7%	182.7%
Other transportation fuels	0.0%	-11.1%	-8.0%	-8.7%	61.7%	-4.4%	-6.1%	122.4%
Commercial	0.0%	18.3%	23.8%	15.6%	16.5%	28.7%	21.4%	17.0%
Nat. gas - comm	0.0%	21.9%	26.2%	21.7%	19.6%	31.2%	32.2%	20.6%
Petroleum - comm	0.0%	-0.4%	25.8%	-39.2%	12.4%	30.7%	-82.3%	8.8%
Coal - comm	0.0%	9.9%	-15.9%	54.7%	-19.0%	-12.6%	104.5%	-16.7%
Industrial	0.0%	8.5%	29.6%	-5.4%	22.9%	57.0%	-12.3%	36.9%
Nat. gas - indust	0.0%	27.4%	51.4%	24.7%	50.2%	83.3%	33.3%	65.4%
Petroleum - indust	0.0%	4.8%	24.5%	-10.8%	16.5%	50.8%	-17.9%	34.2%
Coal - indust	0.0%	-18.7%	0.1%	-49.1%	-14.4%	21.2%	-82.8%	-8.5%
Residential	0.0%	17.9%	22.9%	8.4%	16.3%	27.8%	7.7%	17.5%
Nat. gas - res	0.0%	17.1%	21.2%	4.2%	20.6%	26.0%	1.5%	25.4%
Petroleum - res	0.0%	24.8%	39.4%	30.5%	-8.4%	44.9%	36.8%	-32.1%
Coal - res	0.0%	10.1%	-15.8%	55.1%	-18.1%	-12.4%	105.0%	-13.8%
Electric utility sector	0.0%	19.8%	24.0%	24.5%	38.5%	28.9%	40.8%	54.0%
Fossil fuel use, by fuel and sector	0.0%	18.4%	27.3%	23.6%	33.0%	37.2%	37.6%	43.5%
Coal	0.0%	17.4%	22.1%	19.6%	33.5%	27.9%	32.9%	44.9%
Commercial	0.0%	9.9%	-15.9%	54.7%	-19.0%	-12.6%	104.5%	-16.7%
Industrial	0.0%	-18.7%	0.1%	-49.1%	-14.4%	21.2%	-82.8%	-8.5%
Residential	0.0%	10.1%	-15.8%	55.1%	-18.1%	-12.4%	105.0%	-13.8%
Utility	0.0%	19.7%	23.9%	23.3%	37.0%	28.8%	39.0%	48.9%
Petroleum	0.0%	18.7%	31.9%	31.0%	33.2%	45.5%	49.5%	41.1%
Transportation	0.0%	20.3%	32.6%	36.9%	37.1%	45.3%	60.0%	45.0%
Commercial	0.0%	-0.4%	25.8%	-39.2%	12.4%	30.7%	-82.3%	8.8%
Industrial	0.0%	4.8%	24.5%	-10.8%	16.5%	50.8%	-17.9%	34.2%
Residential	0.0%	24.8%	39.4%	30.5%	-8.4%	44.9%	36.8%	-32.1%
Utility	0.0%	24.1%	28.5%	2.4%	-40.7%	33.6%	-21.5%	124.7%
Natural Gas	0.0%	20.2%	28.8%	15.9%	31.3%	39.6%	21.1%	45.6%
Transportation	0.0%	-11.1%	-7.2%	-1.1%	51.3%	-3.5%	9.2%	95.7%
Commercial	0.0%	21.9%	26.2%	21.7%	19.6%	31.2%	32.2%	20.6%
Industrial	0.0%	27.4%	51.4%	24.7%	50.2%	83.3%	33.3%	65.4%
Residential	0.0%	17.1%	21.2%	4.2%	20.6%	26.0%	1.5%	25.4%
Utility	0.0%	37.1%	42.0%	199.3%	268.3%	47.6%	313.7%	754.5%

Part 2: Estimates of CO_2 emissions from future fossil fuel combustion in Missouri's end-use sectors

CO_2 is a natural byproduct of fossil fuel combustion. The quantity of CO_2 emitted depends primarily on the quantity of fuel burned and the carbon content of the fuel. The estimates summarized here make use of the default carbon content coefficients and methods for estimating CO_2 emissions from quantity of fuel documented in the *1990 Inventory*.

Tables 27, 32, 36 and 40 estimate average annual growth rates for future CO_2 emissions in each of the four end-use sectors. These growth rates are for the period from 1996 to 2015. These growth rates do not include those from 1990 to 1996, a period of rapid growth in emissions.

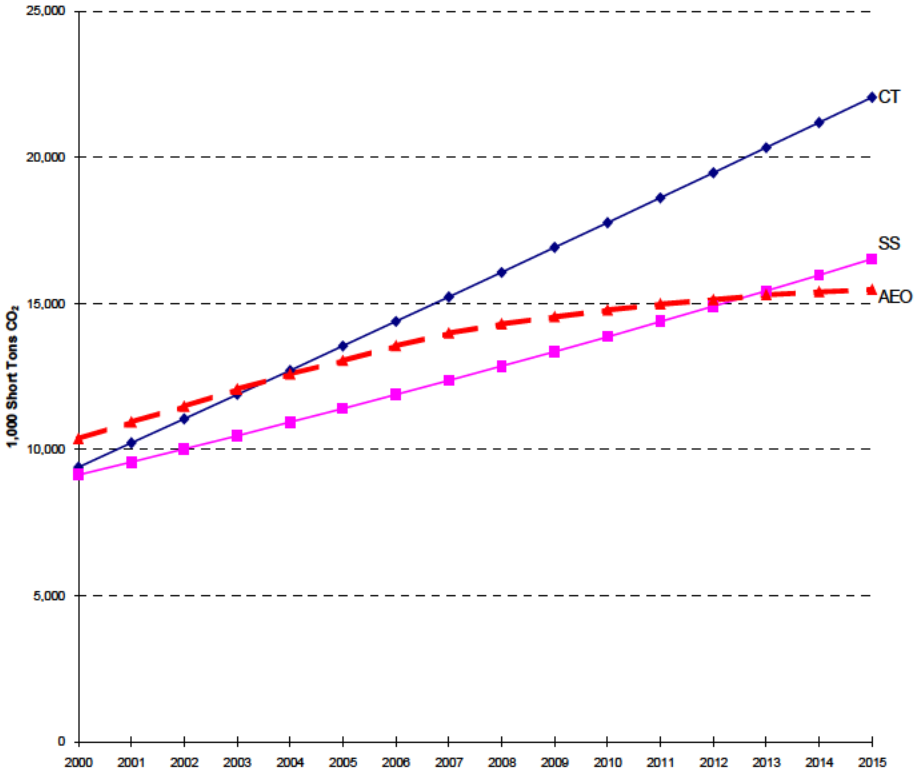
Section 1: Projected CO_2 emissions from fossil fuel combustion in the transportation sector

As Table 27 and Chart 2 illustrate, the CT method projects substantially higher increases in transportation CO_2 emissions than either the SS or AEO method. The CT projection reflects the relatively rapid increase of per capita travel and fuel use in the recent past. The SS method assumes that use of gasoline per capita and diesel and jet fuel per dollar of GSP will remain constant. The AEO projections envision that the rate of increase in per capita emissions will increase more slowly and will eventually decrease as travel behavior changes over time.

Table 27 - Projected growth rate of transportation CO_2 emissions from primary fossil fuel energy use, by method, 1996-2015

	CT	SS	AEO
Transportation	1.5%	1.0%	0.9%
Gasoline	1.0%	0.4%	0.2%
Diesel	2.3%	1.9%	1.6%
Jet fuel	2.5%	1.9%	2.1%
Other	0.1%	0.4%	5.0%

Chart 2 - Projected increase over 1990 baseline of transportation CO_2 emissions from primary fossil fuel use



Projected CO_2 emissions from transportation motor gasoline

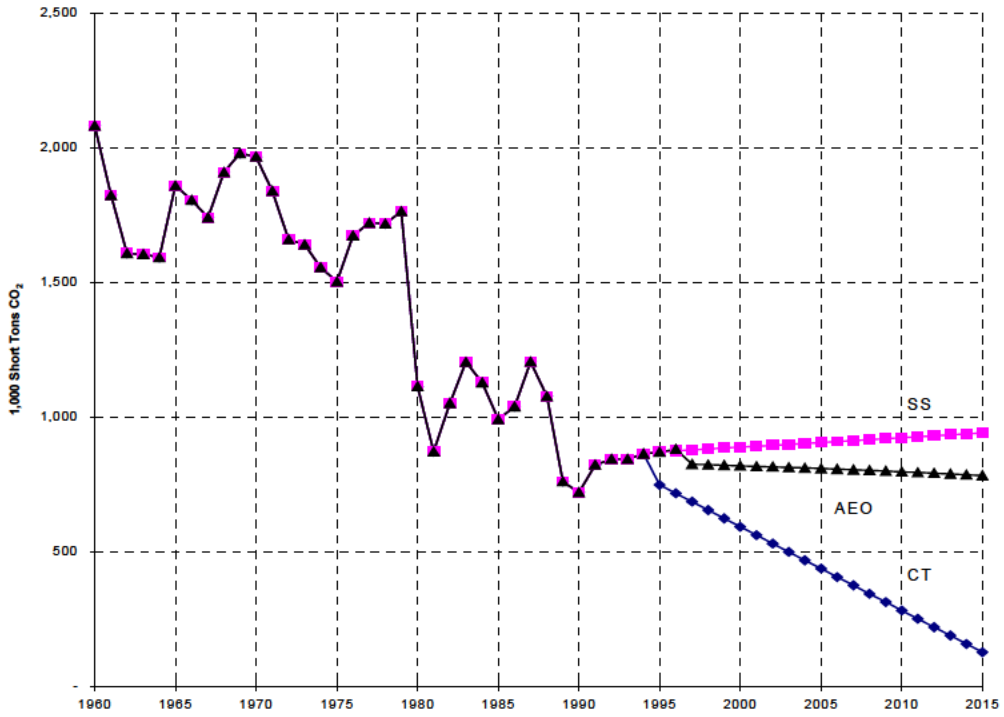
As Table 28 and Chart 4 indicate, the *Annual Energy Outlook 1997* anticipates that over the next 20 years technological, economic and demographic trends will lead to a reduction in gasoline use and associated CO_2. The SS and CT methods produce linear projections that do not take such factors into account. The annual average growth rate in gasoline emissions projected by the CT method, 1.1 percent, is about double that projected by the AEO method.

Table 28 - Projected CO_2 emissions from the Missouri transportation sector's use of motor gasoline as an energy source, by scenario

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	25,826	27,364	28,488	29,037	29,604	30,186
Continuing Trend	25,826	27,364	29,170	30,646	32,199	33,831
AEO	25,826	27,364	28,803	29,305	29,509	29,332

Chart 3 - Steady State (SS), Continuing Trend (CT) and AEO scenario projections of transportation CO_2 emissions from motor gasoline



Projected CO_2 emissions from transportation diesel and jet fuel

As Tables 29 and 30, and Charts 5 and 6 indicate, all scenarios project rapid growth of CO_2 emissions from diesel and jet fuel use in Missouri. However, the *Annual Energy Outlook 1997* anticipates a decline in the growth rate over the next 20 years due to economic changes and improvements in vehicle efficiency.

Table 29 - Projected CO_2 emissions from the Missouri transportation sector's use of diesel fuel as an energy source, by scenario

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	7,578	9,423	10,937	12,035	13,243	14,572
Continuing Trend	7,578	9,423	10,835	12,421	14,008	15,595
AEO	7,578	9,423	11,234	12,461	13,204	13,612

Chart 4 - Steady State (SS), Continuing Trend (CT) and AEO scenario projections of transportation CO_2 emissions from diesel fuel

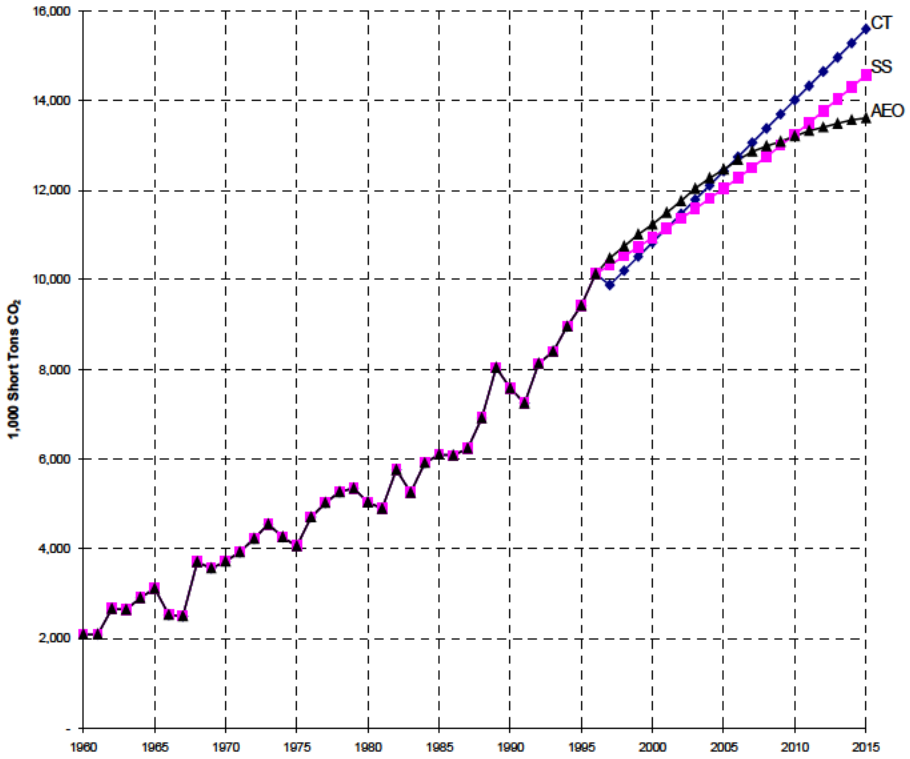
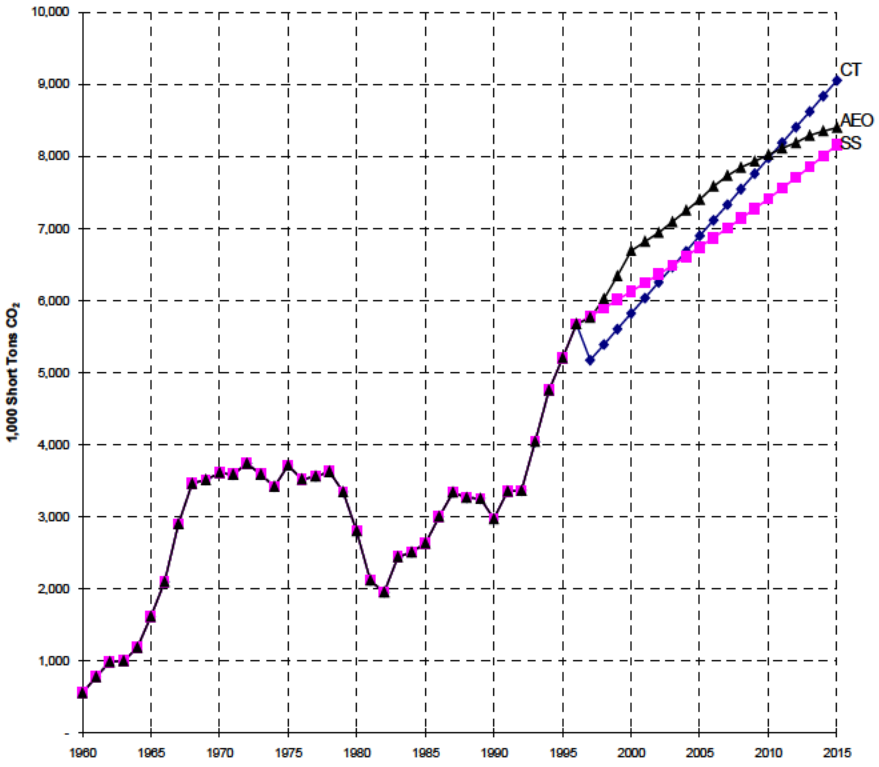


Table 30 - Projected CO_2 emissions from Missouri transportation sector's use of jet fuel as an energy source, by scenario

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	2,971	5,204	6,123	6,738	7,414	8,158
Continuing Trend	2,971	5,204	5,819	6,897	7,974	9,052
AEO	2,971	5,204	6,687	7,398	8,022	8,398

Chart 5 - Steady State (SS), Continuing Trend (CT) and AEO scenario projections of transportation CO_2 emissions from use of jet fuel



Projected CO_2 emissions from other transportation fuel

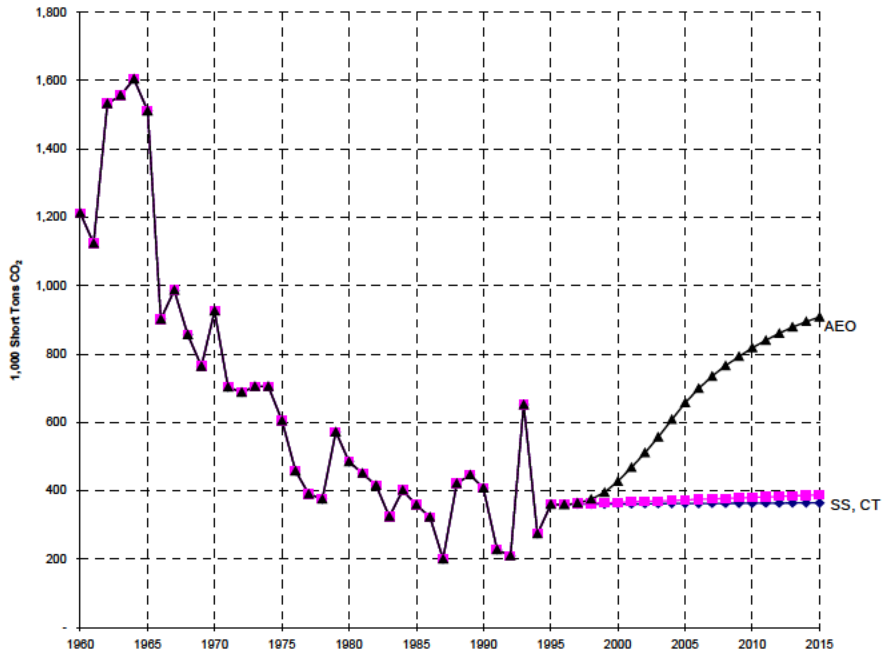
Based in part on expectations for technological advance in alternative fuel vehicles and established legal requirements for incorporating them into fleets, USDOE/EIA anticipates that the use of natural gas will double by 2015 and the use of liquid petroleum gas will grow ninefold. Even at this rapid rate of growth, "other fuels" would constitute only 1.7 percent of transportation fuel use, versus 1.1 percent in 1990. The other methods project that in 2015, there will be less use of alternative fuels than in 1990.

Table 31 - Projected CO_2 emissions from transportation use of other petroleum fuel as an energy source, by scenario

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	408	360	366	373	380	388
Continuing Trend	408	360	361	362	364	365
AEO	408	360	427	658	818	908

Chart 6 - Steady State (SS), Continuing Trend (CT) and AEO scenario projections of transportation CO_2 emissions from other fossil fuel combustion



Section 2: Projected CO_2 emissions from fossil fuel combustion in the commercial sector

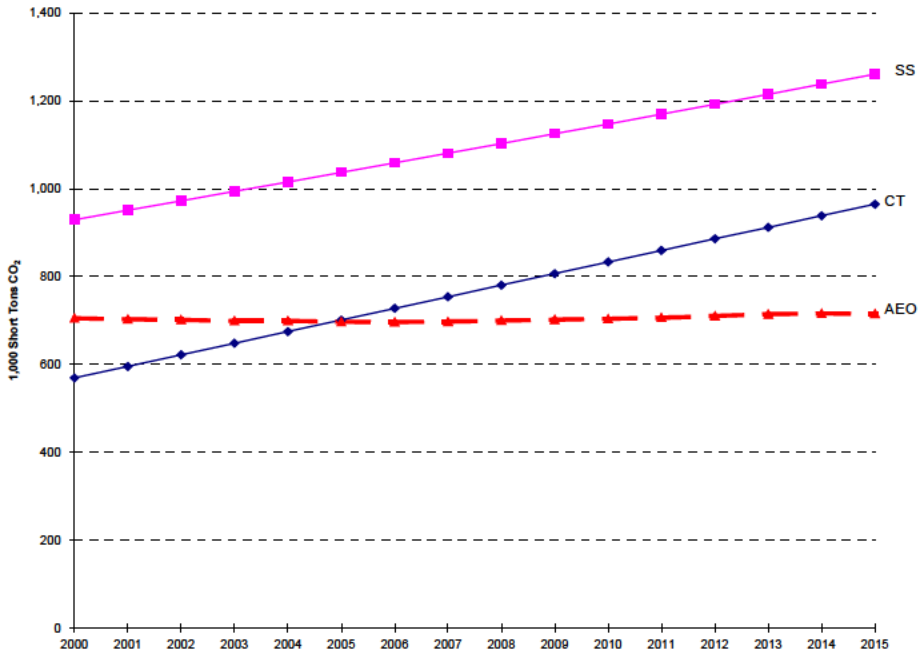
Although CO_2 emissions from primary fossil fuel use in the commercial sector grew by about 18 percent between 1990 and 1996, the CT and AEO analyses projects that emissions will remain nearly constant between 1996 and 2015. Increases illustrated in Chart 8 occurred primarily between 1990 and 1996.

The *Annual Energy Outlook 1997* anticipates little growth in commercial primary fossil fuel energy use between 1996 and 2015 due to slow growth of commercial floor space as well as technological improvements in building shell efficiency and the efficiency of furnaces, boilers and heat pumps fired by natural gas or distillate oil. Increases in commercial energy use will occur primarily in some categories of commercial electricity use.

Table 32 - Projected growth rate of commercial CO_2 emissions from primary fossil fuel energy use, by method, 1996-2015

	CT	SS	AEO
Commercial	0.1%	0.4%	-0.1%
Natural gas	0.4%	0.4%	-0.1%
Petroleum	-9.7%	0.4%	-0.6%
Coal	5.1%	0.5%	0.3%

Chart 7 - Projected increase over 1990 baseline of commercial CO_2 emissions from primary fossil fuel use



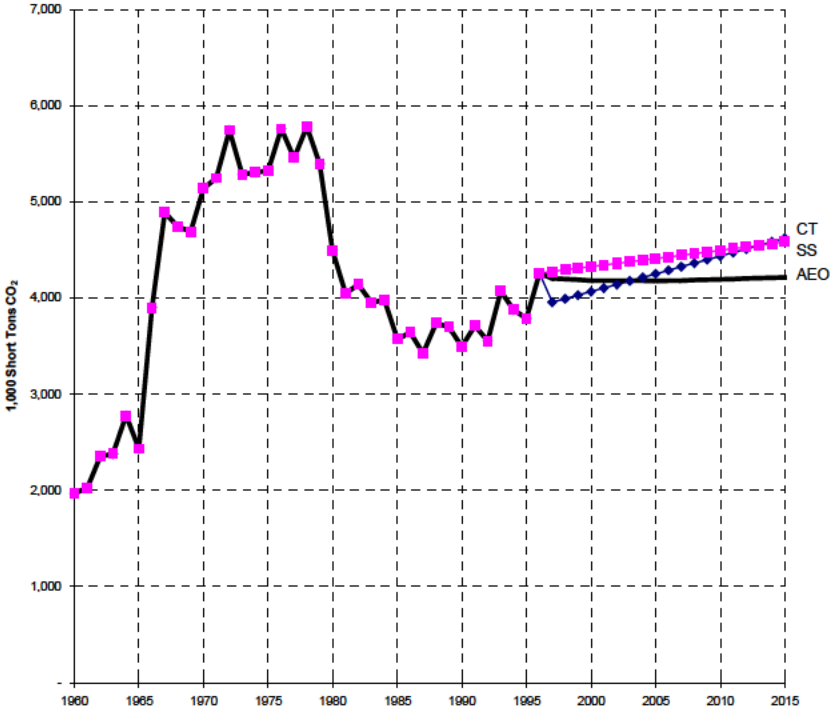
Projected CO_2 emissions from commercial natural gas use

Table 33 - Projected CO_2 emissions from the Missouri commercial sector's use of natural gas as an energy source, by scenario

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	3,494	3,788	4,326	4,409	4,495	4,583
Continuing Trend	3,494	3,788	4,066	4,251	4,435	4,620
AEO	3,494	3,788	4,182	4,179	4,193	4,214

Chart 8 - Steady State (SS), Continuing Trend (CT) and AEO scenario projections of commercial CO_2 emissions from natural gas



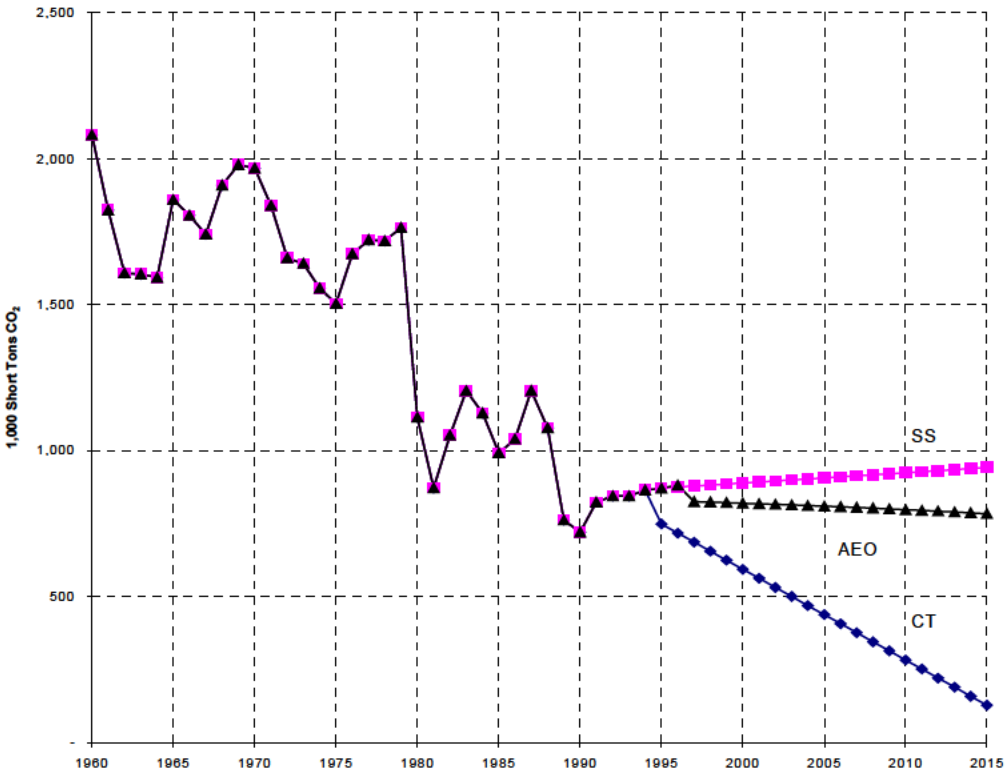
Projected CO_2 emissions from commercial petroleum use

Table 34 - Projected CO_2 emissions from the Missouri commercial sector's use of petroleum as an energy source, by scenario

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	721	872	889	906	924	942
Continuing Trend	721	749	593	438	283	127
AEO	721	871	819	810	798	784

Chart 9 - Steady State (SS), Continuing Trend (CT) and AEO scenario projections of commercial CO_2 emissions from petroleum



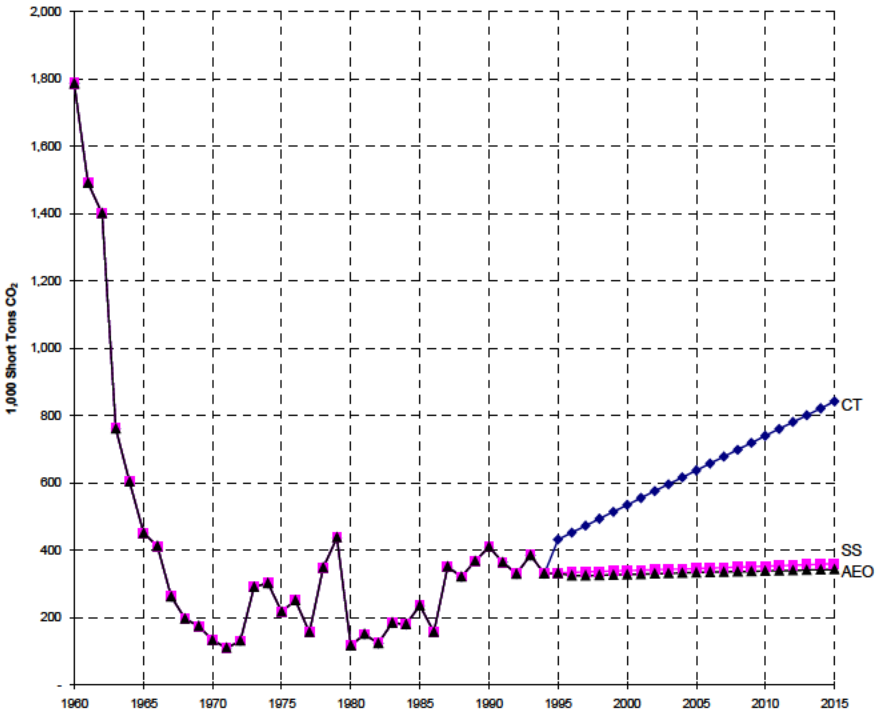
Projected CO_2 emissions from commercial coal use

Table 35 - Projected CO_2 emissions from the Missouri commercial sector's use of coal as an energy source, by scenario

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	410	333	340	346	353	360
Continuing Trend	410	432	535	637	740	843
AEO	410	333	328	334	339	343

Chart 10 - Steady State (SS), Continuing Trend (CT) and AEO scenario projections of commercial CO_2 emissions from coal



Section 3: Projected CO_2 emissions from fossil fuel combustion in the industrial sector

The *Annual Energy Outlook 1997* projects moderate growth in CO_2 emissions from industrial primary fossil fuel use. The *Annual Energy Outlook* projects a plentiful supply and stable price for natural gas. Industrial uses of petroleum include diesel-powered, off-road equipment.

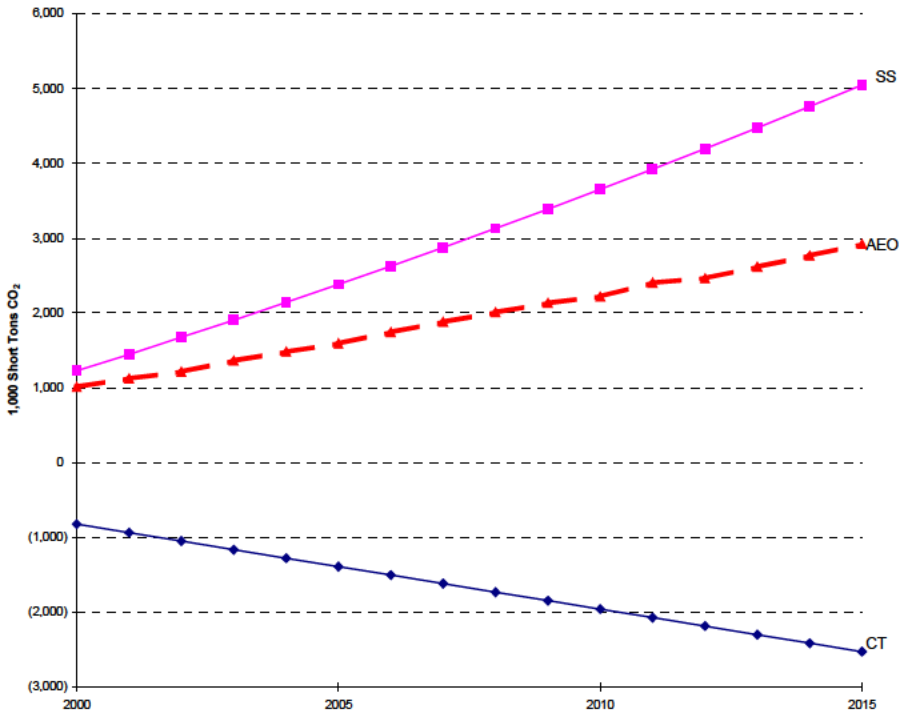
One factor in the *Annual Energy Outlook* projections for industrial CO_2 emissions is the expectation of continued shifts toward less energy-intensive industry. As Chapter 2 points out, this shift may be less a factor in Missouri than elsewhere because the state's industrial sector is already less energy-intensive than the national average.

The SS method projects rapid growth in all fuel types by virtue of its assumption that fuel use in the industrial sectors grows at the rate of GSP. The CT method projects very little change in CO_2 emissions from natural gas use, but decreases in emissions from petroleum and natural gas.

Table 36 - Projected growth rate of industrial CO_2 emissions from primary fossil fuel energy use, by method, 1996-2015

	CT	SS	AEO
Industrial	-1.6%	2.0%	1.2%
Natural gas	0.2%	1.9%	1.4%
Petroleum	-1.5%	1.9%	1.3%
Coal	-7.9%	2.0%	0.5%

Chart 11 - Projected increase over 1990 baseline of industrial CO_2 emissions from primary fossil fuel use



Projected CO_2 emissions from industrial natural gas use

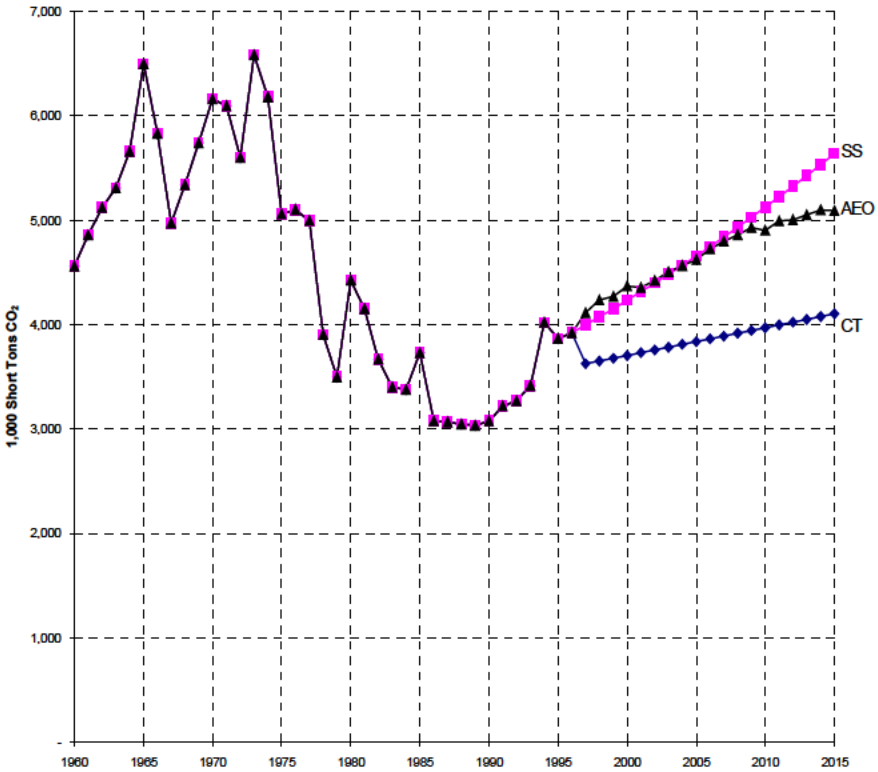
The *Annual Energy Outlook 1997* cites projections for plentiful natural gas supply and stable price as factors that will lead to growth in natural gas consumption by the industry.

Table 37 - Projected CO_2 emissions from the Missouri industrial sector's use of natural gas as an energy source, by scenario

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	3,077	3,865	4,233	4,658	5,125	5,640
Continuing Trend	3,077	3,865	3,705	3,838	3,970	4,103
AEO	3,077	3,865	4,369	4,623	4,903	5,091

Chart 12 - Steady State (SS), Continuing Trend (CT) and AEO scenario projections of industrial CO_2 emissions from combustion of natural gas



Projected CO_2 emissions from industrial petroleum use

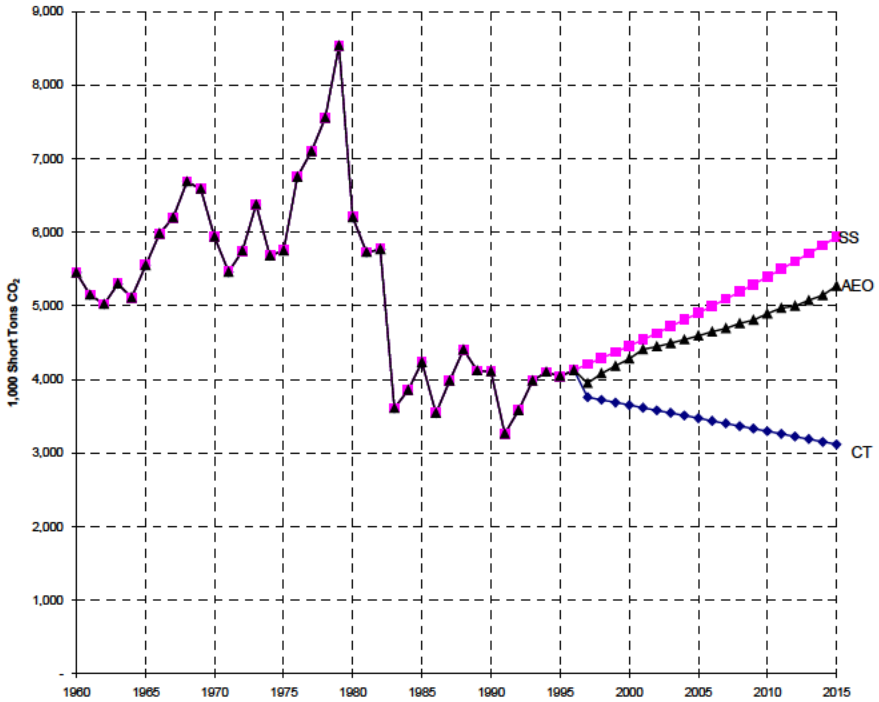
Industrial uses of petroleum include the use of diesel-powered, off-road equipment as well as the use of energy in manufacturing. Non-energy uses of petroleum products such as feedstocks are excluded here but included elsewhere in Chapter 4. The downward trend projected by the CT scenarios is partly an artifact of a downward adjustment in USDOE/EIA estimates for industrial petroleum use between 1990 and 1991.

Table 38 - Projected CO_2 emissions from the Missouri industrial sector's use of petroleum as an energy source, by scenario

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	4,107	4,044	4,455	4,903	5,395	5,936
Continuing Trend	4,107	4,044	3,652	3,474	3,296	3,118
AEO	4,107	3,263	3,580	3,985	4,101	4,044

Chart 13 - Steady State (SS), Continuing Trend (CT) and AEO scenario projections of industrial CO_2 emissions from combustion of petroleum



Projected CO_2 emissions from industrial coal use

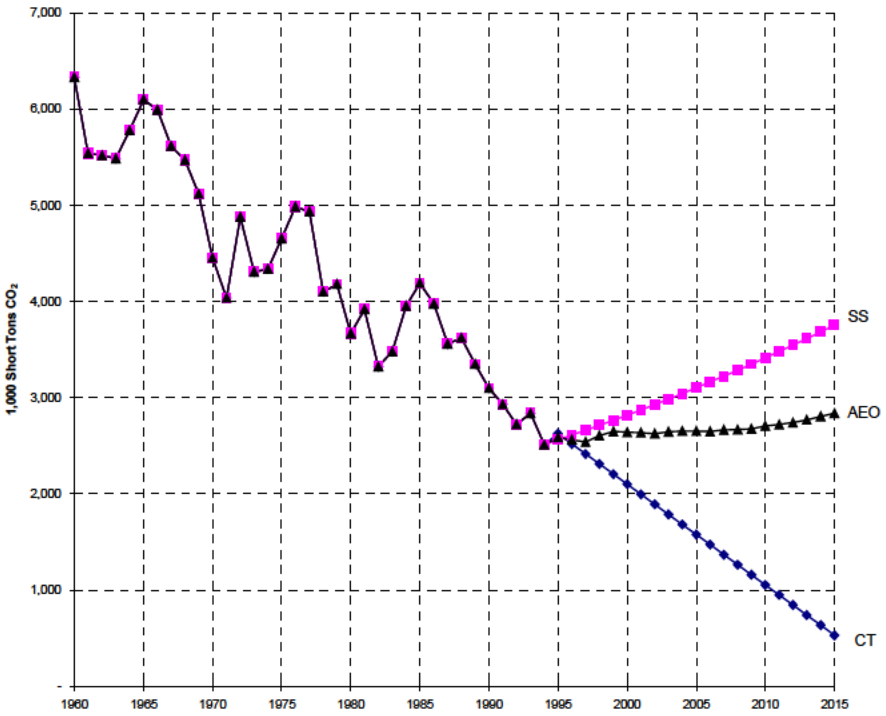
The *Annual Energy Outlook 1997* projects a decrease in CO_2 emissions from coal use due in part to projected changes in steel making technology. The CT projection reflects trends since the 1980s in industrial coal consumption.

Table 39 - Projected CO_2 emissions from the Missouri industrial sector's use of coal as an energy source, by scenario

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	3,100	2,563	2,821	3,104	3,415	3,758
Continuing Trend	3,100	2,626	2,102	1,579	1,056	533
AEO	3,100	2,589	2,642	2,655	2,706	2,839

Chart 14 - Steady State (SS), Continuing Trend (CT) and AEO scenario projections of industrial CO_2 emissions from combustion of coal



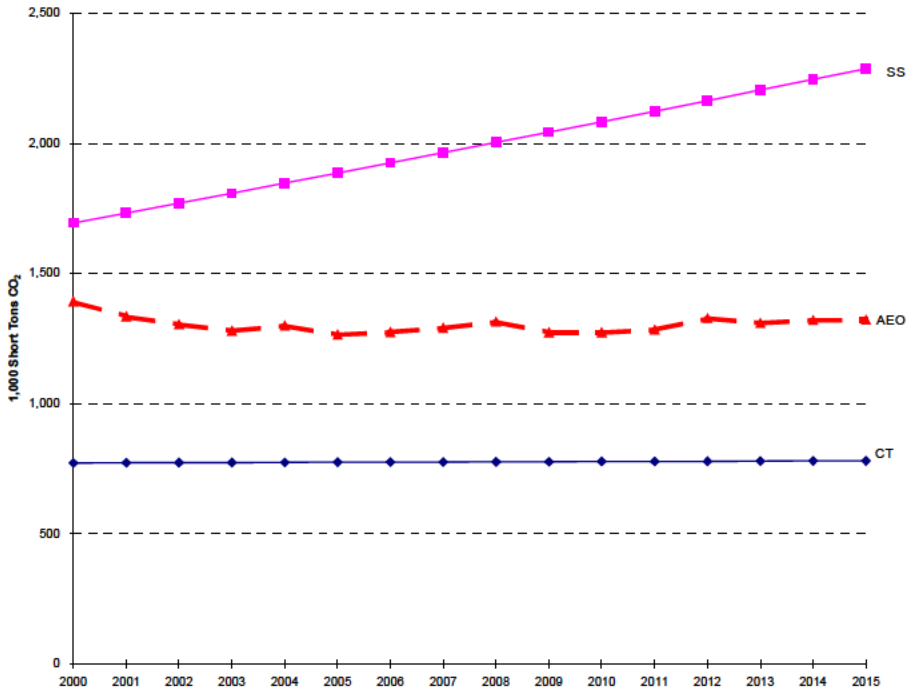
Section 4: Projected CO_2 emissions from fossil fuel combustion in the residential sector

The *Annual Energy Outlook 1997* projects that total CO_2 emissions from residential primary fossil fuel use in 2015 will change little from their level in 1996. The *Annual Energy Outlook* projects that CO_2 emissions from natural gas use will increase due to declining natural gas prices, larger homes and increased use of natural gas heat pumps. However, this increase will be moderated by increased heating efficiency per residential square foot due to building code requirements for new construction. The *Annual Energy Outlook* projects that CO_2 emissions from petroleum use will decrease substantially as residential energy users switch to natural gas or electricity.

Table 40 - Projected growth rate of residential CO_2 emissions from primary fossil fuel energy use, by method, 1996-2015

	CT	SS	AEO
Residential	-0.5%	0.4%	-0.1%
Natural gas	-0.7%	0.4%	0.4%
Petroleum	-0.1%	0.2%	-3.7%
Coal	5.2%	0.6%	0.5%

Chart 15 - Projected increase over 1990 baseline of residential CO_2 emissions from primary fossil fuel use



Projected CO_2 emissions from residential natural gas use

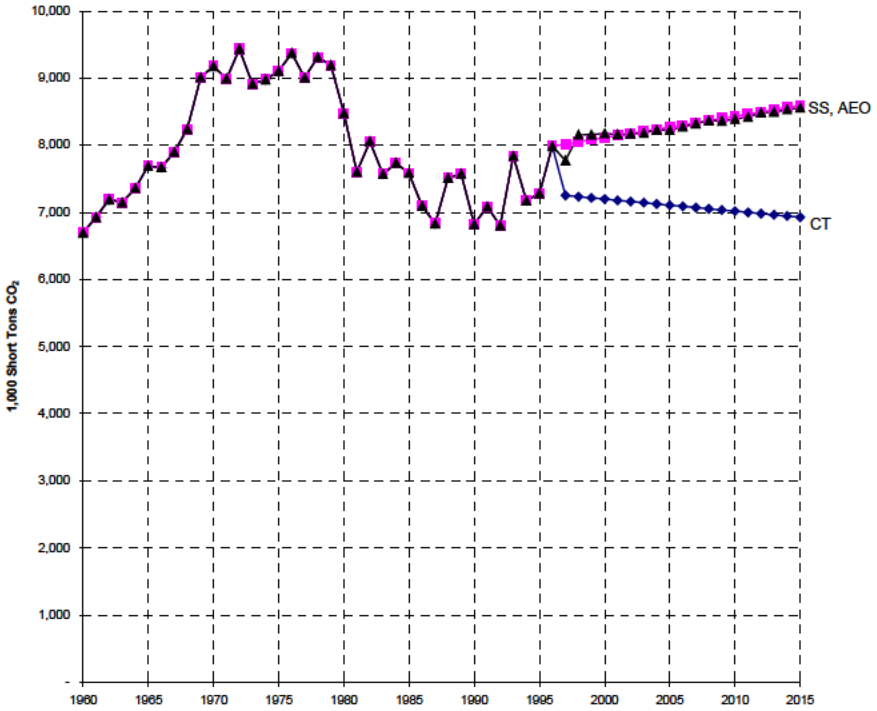
AEO scenarios project that CO_2 emissions from residential natural gas use will increase over the 1996 level of use due to declining natural gas prices, larger homes and increased use of natural gas heat pumps. However, this increase will be moderated by increased heating efficiency per residential square foot due to building code requirements for new construction. The CT scenarios project a decrease from the 1996 consumption level.

Table 41 - Projected CO_2 emissions from the Missouri residential sector's use of natural gas as an energy source, by scenario

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	6,822	7,281	8,112	8,269	8,430	8,596
Continuing Trend	6,822	7,281	7,198	7,108	7,017	6,927
AEO	6,822	7,281	8,174	8,225	8,390	8,558

Chart 16 - Steady State (SS), Continuing Trend (CT) and AEO scenario projections of residential CO_2 emissions from use of natural gas



Projected CO_2 emissions from residential petroleum use

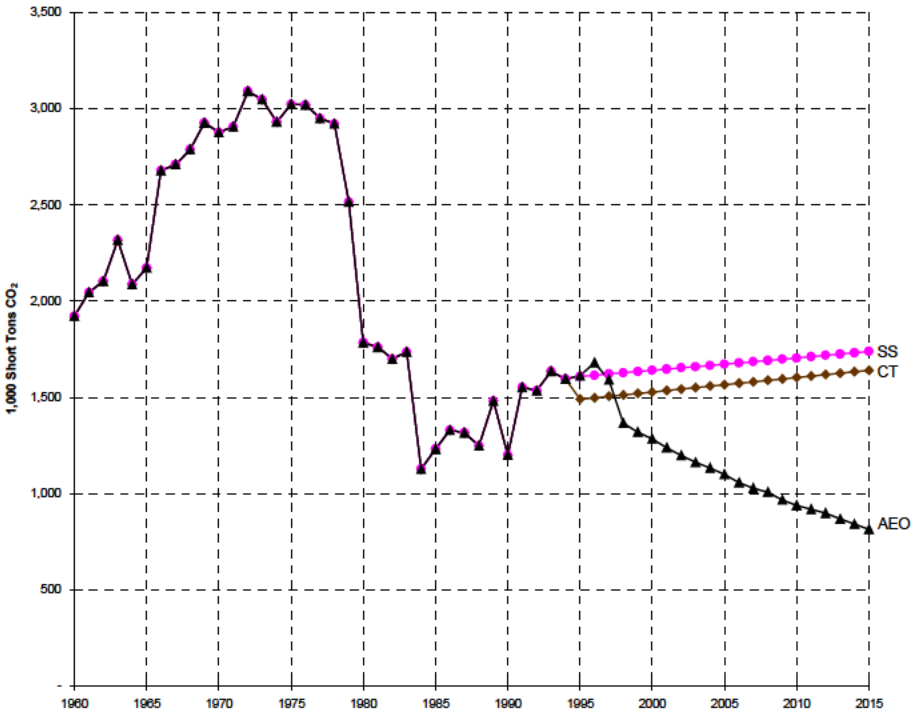
The CT scenario projects a modest increase in residential CO_2 emissions from petroleum use; the AEO scenario projects a decrease as users switch to natural gas or electricity.

Table 42 - Projected CO_2 emissions from the Missouri residential sector's use of petroleum as an energy source, by scenario

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	1,200	1,608	1,640	1,672	1,704	1,738
Continuing Trend	1,200	1,490	1,528	1,565	1,603	1,640
AEO	1,200	1,612	1,284	1,099	938	814

Chart 17 - Steady State (SS), Continuing Trend (CT) and AEO scenario projections of CO_2 emissions from residential use of petroleum



Projected CO_2 emissions from residential coal use

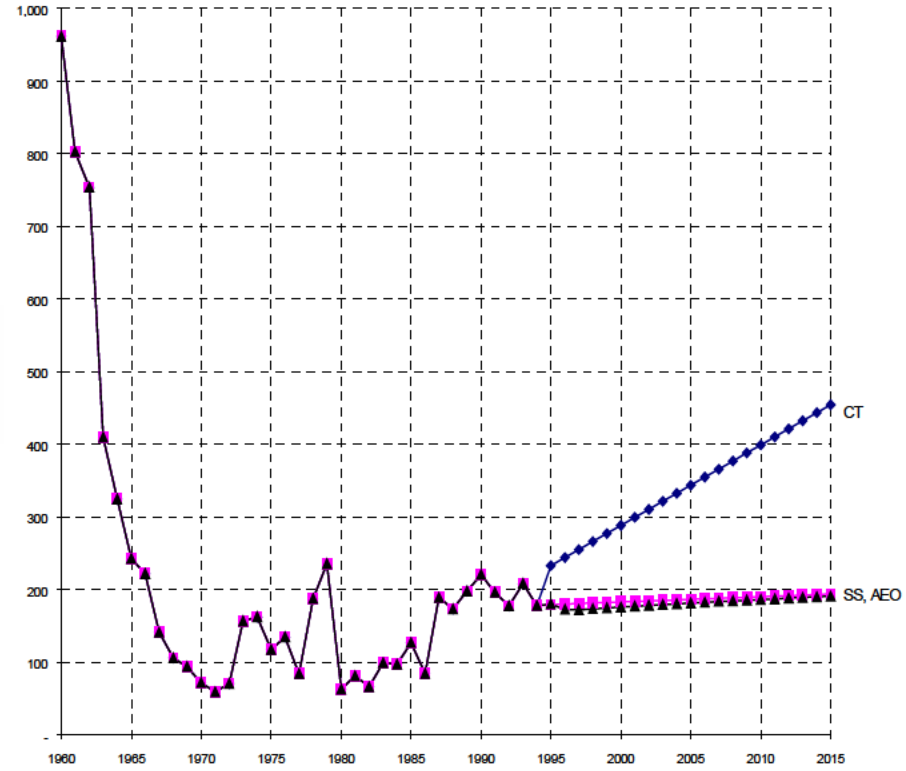
The CT scenario projects a modest increase in residential CO_2 emissions from coal use; the AEO scenario projects a decrease as users switch to natural gas or electricity.

Table 43 - Projected CO_2 emissions from the Missouri residential sector's use of coal as an energy source, by scenario

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	221	180	183	187	191	194
Continuing Trend	221	233	289	344	399	455
AEO	221	180	176	182	187	191

Chart 18 - Steady State (SS), Continuing Trend (CT) and AEO scenario projections of CO_2 emissions from residential use of coal



Section 5: Mix and distribution of CO_2 emissions from coal, petroleum and natural gas use in the end-use sectors

Table 44 summarizes projected increases in end-use sector CO_2 emissions for the periods from 1995 to 2005 and 2005 to 2015. The projections indicate that increases in CO_2 emissions from petroleum use, primarily in the transportation sector,[12] will be the main contributor to the growth of end-use sector emissions.

Table 44 - Projected increase in CO_2 emissions from fossil fuel combustion in Missouri's end-use sectors, by fuel

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	Increase 1995 to 2005			Increase 2005 to 2015		
End-use sectors	**CT**	**SS**	**AEO**	**CT**	**SS**	**AEO**
Natural Gas	262	2,401	2,093	454	3,622	2,666
Petroleum	6,927	6,786	7,447	7,924	6,116	3,316
Coal	-541	535	69	-731	1,752	813
Total	6,647	9,723	9,609	7,648	11,490	6,795
10-year rate of growth	***1.0%***	***1.4%***	***1.4%***	***1.0%***	***1.5%***	***0.9%***

One striking result from this summary is that the AEO method projects a slowdown in the growth rate of end-use sector emissions. The AEO method projects a 1.4 percent growth rate for the period from 1995 to 2005 and only a 0.9 percent growth rate for the period from 2005 to 2015. The projected slowdown occurs in the transportation sector, where the *Annual Energy Outlook 1997* expects decreasing growth in transportation fuel use throughout the projection period and an absolute reduction in gasoline use from 2010 to 2015.

[12] The AEO and SS methods also project significant industrial sector increases in CO_2 emissions from petroleum from 2005 to 2015.

Part 3: Scenario estimates of future CO_2 emissions from fossil fuel combustion in all sectors, allocating utility CO_2 emissions to the four end-use sectors

Section 1: Allocation of utility CO_2 emissions to end-use sectors

CO_2 emissions generated by utilities and allocated to the commercial sector accounted for about 80 percent of that sector's total energy-based CO_2 emissions in 1990. The corresponding percentages for the residential and industrial sectors in 1990 were 72 percent and 55 percent. As Table 45 indicates, these percentage shares will probably increase over the next 20 years, reaching 83 to 87 percent for the commercial sector, 75 to 79 percent for the residential sector and 59 to 69 percent for the industrial sector.

Table 45 - Emissions related to electricity use as a portion of total CO_2 emissions in three end-use sectors, 1990, 2005 and 2015

	Commercial sector		Residential sector		Industrial sector	
	1990	2015	1990	2015	1990	2015
CT Sales (LowNG)	80.0%	86.8%	71.5%	79.4%	54.6%	68.7%
CT Sales (HighNG)		85.9%		78.1%		67.1%
CT (direct)		84.6%		76.3%		64.7%
AEO Sales (LowNG)		84.5%		76.6%		60.6%
AEO (direct)		84.5%		76.6%		60.4%
AEO Sales (HighNG)		83.4%		75.1%		58.5%

Following the example of the *1990 Inventory*, this study allocates projected utility CO_2 emissions to end users based on their projected use of electricity, measured by electricity sales. Through 2015, the residential, commercial and industrial sectors will continue to be the major users of electricity generated from fossil fuel combustion in Missouri's utility sector. As Table 46 indicates, electricity sales to the residential, commercial and industrial sectors are projected to grow through 2015. However, in most cases, the rate of growth will slow after 2005; the exception is the AEO projection of electricity sales to the residential sector.

Table 46 - Projected average annual growth rate of electricity sales, by sector, 1996-2005 and 2005-2015

		Resid.	Comm.	Indust.	Total
AEO electricity sales	1996-2005	0.9%	1.4%	2.0%	1.4%
	2005-2015	1.1%	1.0%	1.5%	1.2%
CT electricity sales	1996-2005	1.9%	2.6%	1.1%	2.0%
	2005-2015	1.6%	2.1%	1.0%	1.7%

Sector shares of total electricity consumption have changed in the past and will continue to change in the future. Table 47 shows the estimated sector shares from 1960 to 2015. These shares were used to allocate projected utility emissions to the different end-use sectors.

Table 47 - Estimated commercial, industrial and residential share of total electricity consumption in Missouri, based on three approaches, 1960-2015

	CT projected sector shares			AEO projected sector shares			SS projected sector shares		
	Comm.	Ind.	Resid.	Comm.	Ind.	Resid.	Comm.	Ind.	Resid.
1960	29%	34%	37%	29%	34%	37%	29%	34%	37%
1990	36%	24%	40%	36%	24%	40%	36%	24%	40%
1995	36%	23%	41%	36%	23%	41%	36%	23%	41%
2000	38%	22%	40%	36%	24%	40%	37%	23%	40%
2005	39%	21%	40%	37%	24%	39%	38%	23%	40%
2010	40%	20%	40%	37%	25%	39%	38%	22%	39%
2015	41%	20%	40%	36%	25%	39%	38%	22%	39%

The sales projections underlying Tables 46 and 47 are based on three different approaches to estimating sector shares of electricity sales — the CT, AEO and SS methods.

- The CT approach to estimating sector shares is based on trend projection of Missouri electricity sales to the three sectors between 1980 and 1996, and projects that the residential and commercial sectors will account for 80 percent of all electricity sales in 2015. Per capita use of electricity in Missouri's residential and commercial sectors rose from 1980 to 1996, whereas electricity use per dollar of GSP declined in Missouri's industrial sector. The CT method projects that these trends will continue.

- The AEO approach to estimating sector shares is based on *Annual Energy Outlook 1997* projections for the North West Central region and projects that the residential and commercial sectors will account for 75 percent of all electricity sales in 2015. Both the projected increase in residential and commercial per capita sales, and the projected decline in industrial sales per GSP, are more moderate than those estimated by the CT method. As Chapter 2 points out, since Missouri industry is already less energy-intensive than the U.S. average, the AEO projection for industrial sales may be more realistic. On the other hand, the AEO projection for residential and commercial electricity sales assumes that sales will be moderated by efficiency gains and market saturation of current appliances. As Chapter 2 points out, the introduction of new uses for electricity, rapid economic growth, or lower electricity prices resulting from market restructuring could push residential and commercial sales upward toward the CT estimate.

- Since the SS method was not used to estimate electricity sales, there is no independent SS estimate for the distribution of electricity sales by sector. Therefore, the average of the AEO and CT estimates is used to allocate utility CO_2 emissions across end-use sectors.

Table 48 summarizes the projections of energy-based CO_2 emissions in 2015 that result when the sector shares in Table 47 are used as the basis for allocating electricity emissions to Missouri's four end-use sectors. The table indicates the relative shares of allocated utility emissions and emissions from primary fossil fuel use in 2015.

Table 48 - Projected total energy-based CO_2 emissions in Missouri, by end-use sector and estimation method, 2015

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1996	CT direct estimate	CT Sales LowNG	CT Sales HighNG	AEO direct estimate	AEO Sales LowNG	AEO Sales HighNG	SS direct estimate
Transportation	36,782	44,208	58,842	58,842	58,842	52,250	52,250	52,250	53,303
Gasoline	25,826	28,044	33,831	33,831	33,831	29,332	29,332	29,332	30,186
Diesel	7,578	10,131	15,595	15,595	15,595	13,612	13,612	13,612	14,572
Jet	2,971	5,672	9,052	9,052	9,052	8,398	8,398	8,398	8,158
Other	408	360	365	365	365	908	908	908	388
Commercial	23,104	29,089	36,275	42,391	39,696	34,408	34,556	32,153	32,208
Electricity	18,479	23,625	30,685	36,801	34,106	29,067	29,215	26,812	26,322
Nat. Gas	3,494	4,258	4,620	4,620	4,620	4,214	4,214	4,214	4,583
Petroleum	721	881	127	127	127	784	784	784	942
Coal	410	325	843	843	843	343	343	343	360
Industrial	22,649	24,927	21,962	24,794	23,546	33,371	33,474	31,807	30,630
Electricity	12,365	14,314	14,208	17,040	15,792	20,170	20,273	18,605	15,297
Nat. Gas	3,077	3,921	4,103	4,103	4,103	5,091	5,091	5,091	5,640
Petroleum	4,107	4,127	3,118	3,118	3,118	5,272	5,272	5,272	5,936
Coal	3,100	2,564	533	533	533	2,839	2,839	2,839	3,758
Residential	28,937	35,187	38,023	43,803	41,255	40,793	40,952	38,370	37,425
Electricity	20,694	25,349	29,000	34,780	32,233	31,230	31,389	28,807	26,897
Nat. Gas	6,822	7,986	6,927	6,927	6,927	8,558	8,558	8,558	8,596
Petroleum	1,200	1,680	1,640	1,640	1,640	814	814	814	1,738
Coal	221	173	455	455	455	191	191	191	194
Total	***111,472***	***133,411***	***155,102***	***169,830***	***163,339***	***160,822***	***161,233***	***154,580***	***153,566***

Tables 49 through 52 summarize projected emissions for the transportation, industrial, residential and commercial sectors. These tables also indicate the annual average growth rates of CO_2 emissions for 1990 to 2015, 1996 to 2005 and 2005 to 2015. Examination of the projected growth rates in these tables and Table 5 leads to the following conclusions:

1. Over the next 20 years, CO_2 emissions from fossil fuel combustion will probably not grow as rapidly as they did during 1990 to 1996, when they grew at a brisk 3.1 percent average annual rate.

2. In most cases, the growth rate of CO_2 emissions from fossil fuel combustion will gradually decrease. The deceleration in the rate of emissions increase is most pronounced for the AEO-based scenarios than the CT-based scenarios.

3. Both the CT and AEO methods project an accelerating rate of emissions in the residential sector.

Table 49 - Projected CO_2 emissions from fossil fuel combustion in Missouri's industrial sector, by scenario – including utility CO_2 emissions allocated in proportion to projected industrial electricity use, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

		Projected CO_2 emissions, including allocated utility emissions						Average annual growth rate		
		1990	1996	2000	2005	2010	2015	1990-2015	1996-2005	2005-2015
Low	SS direct	22,649	24,989	26,216	27,570	29,035	30,630			
	AEO sales HighNG	22,649	24,985	26,890	28,853	30,671	31,807	1.37%	1.61%	0.98%
	CT direct	22,649	24,927	22,727	22,444	22,191	21,962	-0.12%	-1.16%	-0.22%
Mid	AEO direct	22,649	24,985	28,367	29,626	30,753	33,371	1.56%	1.91%	1.20%
	AEO sales LowNG	22,649	24,985	26,953	29,129	31,265	33,474	1.57%	1.72%	1.40%
	CT sales HighNG	22,649	24,927	23,692	23,904	24,031	23,546	0.16%	-0.46%	-0.15%
High	CT sales LowNG	22,649	24,927	23,752	24,153	24,535	24,794	0.36%	-0.35%	0.26%

Table 50 - Projected CO_2 emissions from fossil fuel combustion in Missouri's residential sector, by scenario – including utility CO_2 emissions allocated in proportion to projected residential electricity use, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

		Projected CO_2 emissions, including allocated utility emissions						Average annual growth rate		
		1990	1996	2000	2005	2010	2015	1990-2015	1996-2005	2005-2015
Low	SS direct	28,937	35,540	35,964	36,206	36,717	37,425			
	AEO sales HighNG	28,937	35,768	36,307	36,930	37,980	38,370	1.14%	0.36%	0.38%
	CT direct	28,937	35,187	33,381	34,921	36,469	38,023	1.10%	-0.08%	0.85%
Mid	AEO direct	28,937	35,768	38,832	38,178	38,109	40,793	1.38%	0.73%	0.66%
	AEO sales LowNG	28,937	35,768	36,415	37,376	38,912	40,952	1.40%	0.49%	0.92%
	CT sales HighNG	28,937	35,187	35,152	37,711	40,111	41,255	1.43%	0.77%	0.90%
High	CT sales LowNG	28,937	35,187	35,262	38,187	41,108	43,803	1.67%	0.91%	1.38%

Table 51 - Projected CO_2 emissions from fossil fuel combustion in Missouri's commercial sector, by scenario – including utility CO_2 emissions allocated in proportion to projected commercial electricity use, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

		Projected CO_2 emissions, including allocated utility emissions						Average annual growth rate		
		1990	1996	2000	2005	2010	2015	1990-2015	1996-2005	2005-2015
Low	SS direct	23,104	28,674	29,482	30,587	31,476	32,208	1.34%	0.72%	0.52%
	AEO sales HighNG	23,104	28,450	29,075	30,891	32,174	32,153	1.33%	0.92%	0.40%
	CT direct	23,104	29,089	28,733	31,282	33,793	36,275	1.82%	0.81%	1.49%
Mid	AEO direct	23,105	28,450	31,323	32,055	32,295	34,408	1.61%	1.33%	0.71%
	AEO sales LowNG	23,105	28,450	29,171	31,306	33,052	34,556	1.62%	1.07%	0.99%
	CT sales HighNG	23,104	29,089	30,444	34,078	37,552	39,696	2.19%	1.77%	1.54%
High	CT sales LowNG	23,104	29,089	30,550	34,554	38,582	42,391	2.46%	1.93%	2.07%

Table 52 - Projected CO_2 emissions from fossil fuel combustion in Missouri's transportation sector, by scenario, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

		Projected CO_2 emissions, including allocated utility emissions						Average annual growth rate		
		1990	1996	2000	2005	2010	2015	1990-2015	1996-2005	2005-2015
Low	SS direct	36,782	44,208	45,915	48,183	50,641	53,303	1.49%	0.96%	1.02%
	AEO sales HighNG	36,782	44,207	47,150	49,821	51,554	52,250	1.41%	1.34%	0.48%
	CT direct	36,782	44,208	46,185	50,326	54,545	58,842	1.90%	1.45%	1.58%
Mid	AEO direct	36,782	44,207	47,150	49,821	51,554	52,250	1.41%	1.34%	0.48%
	AEO sales LowNG	36,782	44,207	47,150	49,821	51,554	52,250	1.41%	1.34%	0.48%
	CT sales HighNG	36,782	44,208	46,185	50,326	54,545	58,842	1.90%	1.45%	1.58%
High	CT sales LowNG	36,782	44,208	46,185	50,326	54,545	58,842	1.90%	1.45%	1.58%

Section 2: Scenario projections of increases in CO_2 emissions over the 1990 baseline

Because many proposals for reducing greenhouse gas emissions set targets related to the level of emissions in 1990, it is relevant to summarize projected increases in Missouri's CO_2 emissions relative to Missouri's 1990 emissions baseline.

Tables 53 through 56, together with Charts 20 through 23, give projections for each end-use sector. The projections include utility emissions allocated according to each sector's projected consumption of electricity, and are organized around the low-, midrange- and high-CO_2 scenarios developed in this chapter and Chapter 2. The tables list the seven scenario methods in the same order that they are listed in Table 5 — from low to high total CO_2 emissions.

For each scenario method, the tables provide the annual average growth rate of CO_2 emissions between 1996 and 2015. This provides a bottom-line measure of projected future growth in CO_2 emissions.

The tables also provide annual average growth rates for 1990 to 1996 and each subsequent five-year growth period. Comparing the sequence of five-year growth rates indicates the pattern of growth projected for any given scenario.

Projected increases in commercial CO_2 emissions

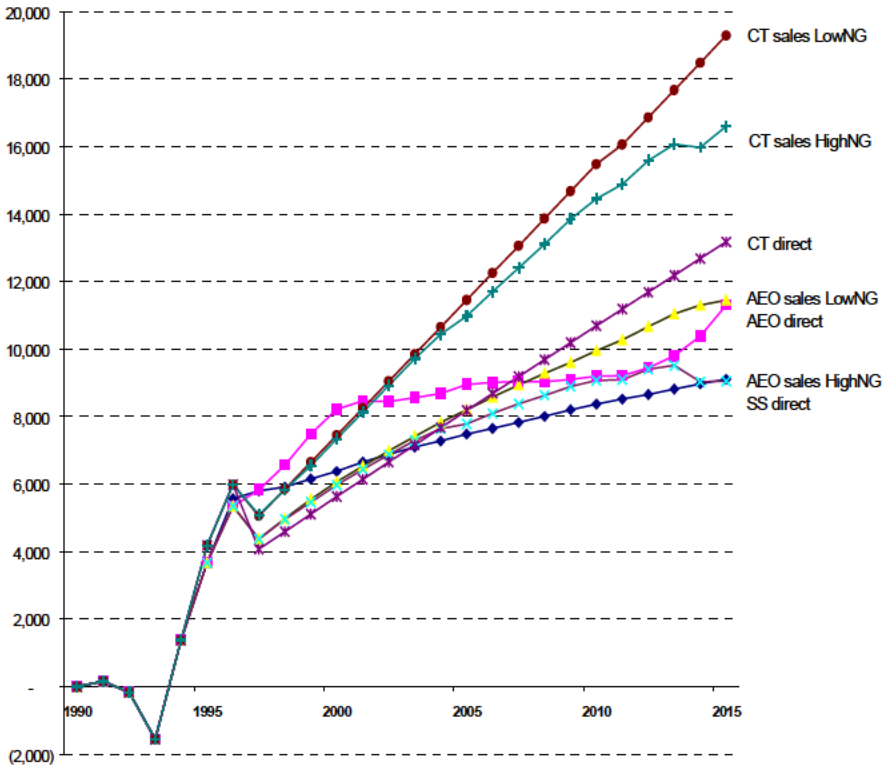
Table 53 - Missouri commercial CO_2 emissions from fossil fuel combustion and use of electricity, 1990-2015 — projected increase over 1990 baseline

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1996	2000	2005	2010	2015	Growth rate 1996-2015
SS direct	5,570	6,378	7,482	8,372	9,103	0.61%
AEO sales HighNG	5,346	5,970	7,786	9,070	9,048	0.65%
CT direct	5,985	5,628	8,178	10,689	13,171	1.17%
AEO direct	5,345	8,218	8,950	9,191	11,303	1.01%
AEO sales LowNG	5,345	6,066	8,201	9,948	11,451	1.03%
CT sales HighNG	5,985	7,339	10,973	14,448	16,591	1.65%
CT sales LowNG	5,985	7,445	11,450	15,478	19,287	2.00%

	Growth rate 1990-1996	Growth rate 1996-2000	Growth rate 2000-2005	Growth rate 2005-2010	Growth rate 2010-2015
SS direct	3.67%	0.70%	0.74%	0.57%	0.46%
AEO sales HighNG	3.53%	0.54%	1.22%	0.82%	-0.01%
CT direct	3.91%	-0.31%	1.71%	1.56%	1.43%
AEO direct	3.53%	2.43%	0.46%	0.15%	1.28%
AEO sales LowNG	3.53%	0.63%	1.42%	1.09%	0.89%
CT sales HighNG	3.91%	1.14%	2.28%	1.96%	1.12%
CT sales LowNG	3.91%	1.23%	2.49%	2.23%	1.90%

Chart 19 - Missouri commercial CO_2 emissions from fossil fuel combustion and use of electricity, 1990-2015 — projected increase over 1990 baseline



Projected increases in industrial CO_2 emissions

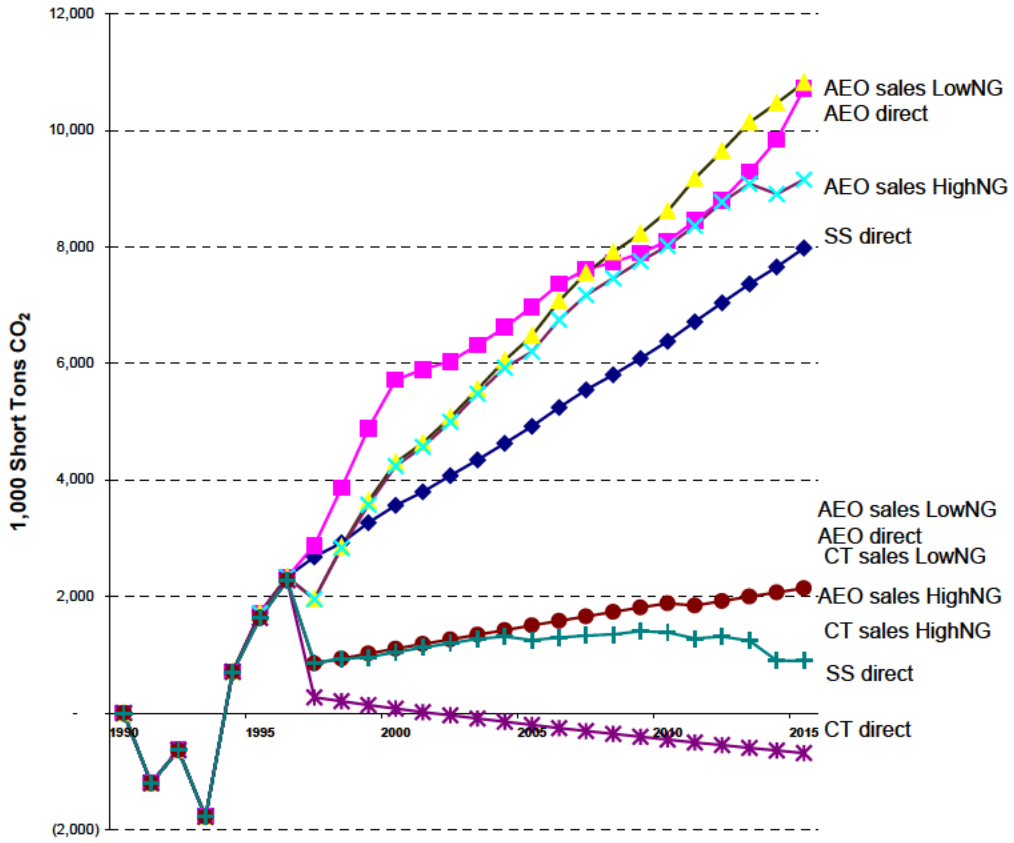
Table 54 - Missouri industrial CO_2 emissions from fossil fuel combustion and use of electricity, 1990-2015 — projected increase over 1990 baseline

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1996	2000	2005	2010	2015	Growth rate 1996-2015
SS direct	2,340	3,567	4,921	6,386	7,982	1.08%
AEO sales HighNG	2,336	4,241	6,204	8,022	9,158	1.28%
CT direct	2,278	79	(205)	(457)	(686)	-0.66%
AEO direct	2,336	5,718	6,977	8,104	10,722	1.53%
AEO sales LowNG	2,336	4,304	6,480	8,616	10,825	1.55%
CT sales HighNG	2,278	1,043	1,255	1,382	897	-0.30%
CT sales LowNG	2,278	1,103	1,504	1,887	2,145	-0.03%

	Growth rate 1990-1996	Growth rate 1996-2000	Growth rate 2000-2005	Growth rate 2005-2010	Growth rate 2010-2015
SS direct	1.65%	1.21%	1.01%	1.04%	1.08%
AEO sales HighNG	1.65%	1.85%	1.42%	1.23%	0.73%
CT direct	1.61%	-2.28%	-0.25%	-0.23%	-0.21%
AEO direct	1.65%	3.22%	0.87%	0.75%	1.65%
AEO sales LowNG	1.65%	1.91%	1.57%	1.43%	1.37%
CT sales HighNG	1.61%	-1.26%	0.18%	0.11%	-0.41%
CT sales LowNG	1.61%	-1.20%	0.34%	0.31%	0.21%

Chart 20 - Missouri industrial CO_2 emissions from fossil fuel combustion and use of electricity, 1990-2015 — projected increase over 1990 baseline



Projected increases in residential CO_2 emissions

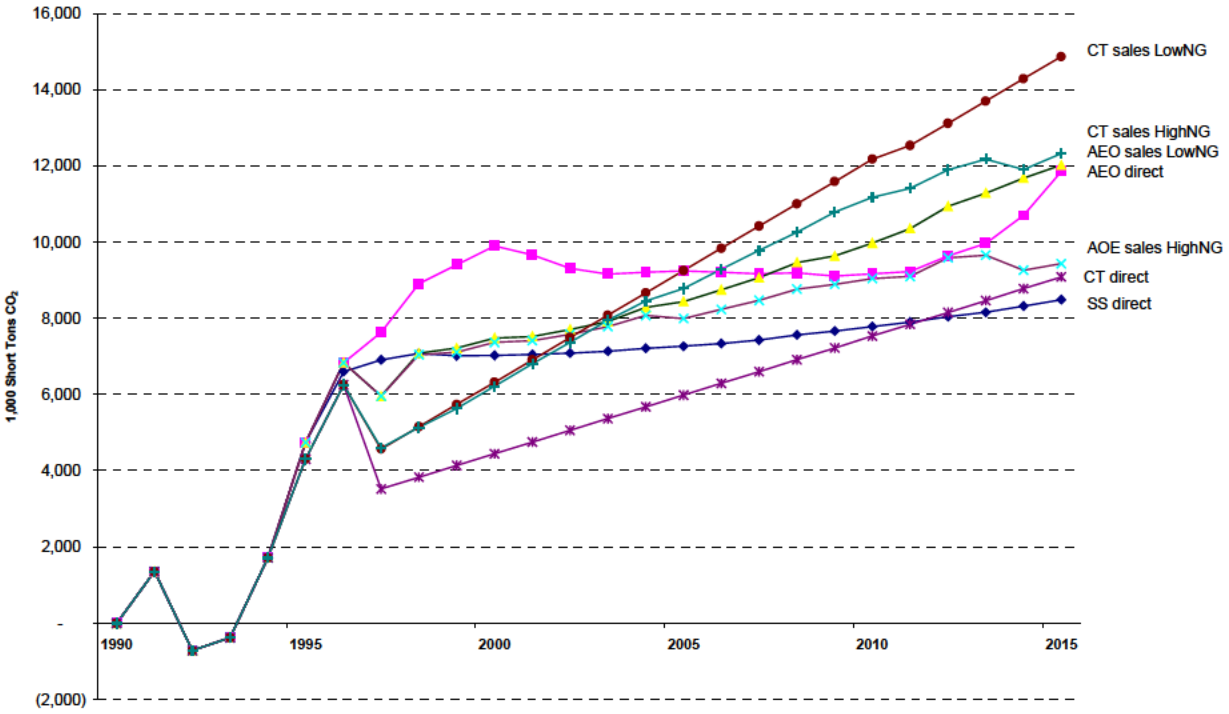
Table 55 - Missouri residential CO_2 emissions from fossil fuel combustion and use of electricity, 1990-2015 — projected increase over 1990 baseline

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1996	2000	2005	2010	2015	Growth rate 1996-2015
SS direct	6,603	7,027	7,270	7,780	8,488	0.27%
AEO sales HighNG	6,831	7,370	7,993	9,044	9,434	0.37%
CT direct	6,251	4,444	5,985	7,533	9,086	0.41%
AEO direct	6,831	9,895	9,241	9,172	11,856	0.69%
AEO sales LowNG	6,831	7,478	8,439	9,975	12,015	0.71%
CT sales HighNG	6,251	6,215	8,775	11,174	12,319	0.84%
CT sales LowNG	6,251	6,325	9,251	12,172	14,866	1.16%

	Growth rate 1990-1996	Growth rate 1996-2000	Growth rate 2000-2005	Growth rate 2005-2010	Growth rate 2010-2015
SS direct	3.49%	0.30%	0.13%	0.28%	0.38%
AEO sales HighNG	3.60%	0.37%	0.34%	0.56%	0.20%
CT direct	3.31%	-1.31%	0.91%	0.87%	0.84%
AEO direct	3.60%	2.08%	-0.34%	-0.04%	1.37%
AEO sales LowNG	3.60%	0.45%	0.52%	0.81%	1.03%
CT sales HighNG	3.31%	-0.03%	1.42%	1.24%	0.56%
CT sales LowNG	3.31%	0.05%	1.61%	1.49%	1.28%

Chart 21 - Missouri residential CO_2 emissions from fossil fuel combustion and use of electricity, 1990-2015 — projected increase over 1990 baseline



Projected increases in CO_2 emissions from transportation

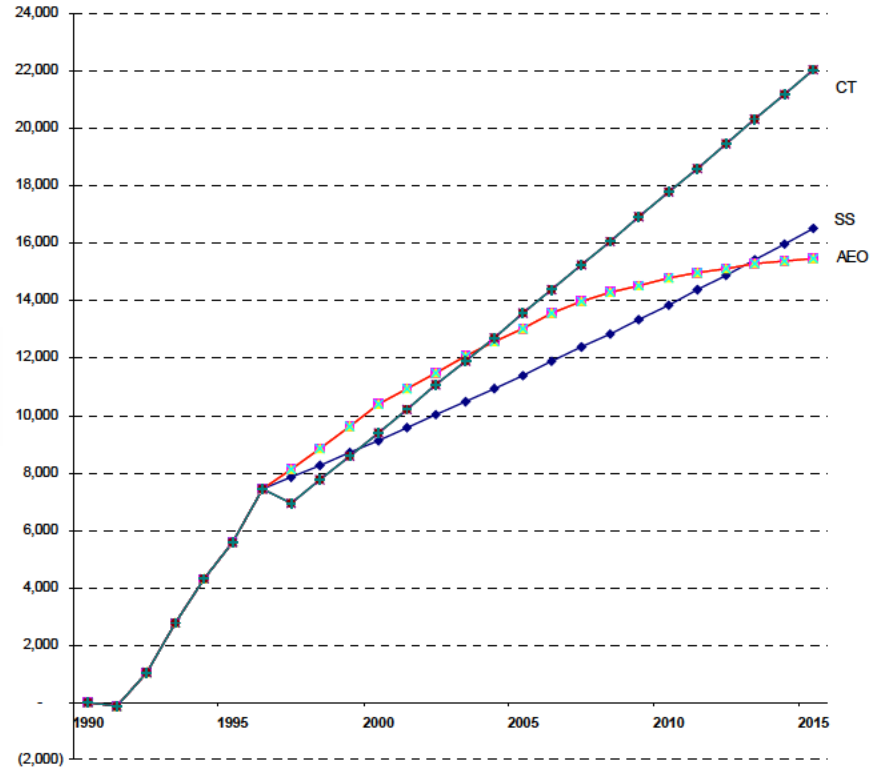
Table 56 - Missouri transportation sector CO_2 emissions from fossil fuel combustion, 1990-2015 — projected increase over 1990 baseline

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1996	2000	2005	2010	2015
SS direct	7,425	9,132	11,401	13,859	16,521
AEO sales HighNG	7,424	10,368	13,039	14,771	15,468
CT direct	7,425	9,403	13,544	17,763	22,059
AEO direct	7,424	10,368	13,039	14,771	15,468
AEO sales LowNG	7,424	10,368	13,039	14,771	15,468
CT sales HighNG	7,425	9,403	13,544	17,763	22,059
CT sales LowNG	7,425	9,403	13,544	17,763	22,059

	Growth rate 1990-1996	Growth rate 1996-2000	Growth rate 2000-2005	Growth rate 2005-2010	Growth rate 2010-2015
SS direct	3.11%	0.95%	0.97%	1.00%	1.03%
AEO sales HighNG	3.11%	1.62%	1.11%	0.69%	0.27%
CT direct	3.11%	1.10%	1.73%	1.62%	1.53%
AEO direct	3.11%	1.62%	1.11%	0.69%	0.27%
AEO sales LowNG	3.11%	1.62%	1.11%	0.69%	0.27%
CT sales HighNG	3.11%	1.10%	1.73%	1.62%	1.53%
CT sales LowNG	3.11%	1.10%	1.73%	1.62%	1.53%

Chart 22 - Missouri transportation sector CO_2 emissions from fossil fuel combustion, 1990-2015 — projected increase over 1990 baseline



Greenhouse Gas Emission Trends and Projections for Missouri, 1990-2015 Technical Report

Chapter 5

Greenhouse Gas Emissions from "Other" Sources – Trends and Projections

Chapter 5: Greenhouse gas emissions from "other" sources — trends and projections

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Chapter 5: Greenhouse gas emissions from "other" sources — trends and projections

The leading source of greenhouse gas emissions in Missouri, as in other states, is combustion of fossil fuels for energy. Chapters 2 through 4 estimated CO_2 emissions from this source. Fossil fuel combustion accounted for about 75 percent of Missouri's anthropogenic greenhouse gas emissions in 1990. This chapter discusses the sources for the other 25 percent of emissions. In 1990, these "other" sources emitted a total of about 36.8 million tons (STCDE) of greenhouse gas emissions, consisting of about 11.7 million tons of CO_2, 16.7 million tons (STCDE) of methane (CH_4), 3.8 million tons (STCDE) of nitrous oxide (N_2O) and 4.6 million tons (STCDE) of perfluorinated carbons (PFCs).[1]

Under the scenarios developed for this study, the share of these sources in total greenhouse gas emissions is projected to decline. A decline in their share is projected to occur due to a projected 2.5 million ton (STCDE) decrease in total emissions from these sources as well as projected increases in CO_2 emissions from fossil fuel combustion.

Part 1 of this chapter discusses and estimates CO_2 emissions from sources other than fossil fuel combustion. Following the *1990 Inventory,* four sources of CO_2 emissions are covered here: land use changes, which accounted for about 3.6 percent of CO_2 emissions in 1990; industrial and agricultural uses of limestone, which accounted for 3.6 percent; and two sources related to fossil fuel use (non-energy use of fossil fuels, and oxidation of carbon monoxide) which each accounted for just over 1 percent of CO_2 emissions in 1990. Their combined 9.5 percent share of CO_2 emissions in 1990 is projected to decline to less than 8 percent by 2015, increasing the role of fossil fuel combustion as a source of CO_2 emissions in Missouri.

The remainder of the chapter discusses and estimates statewide emissions of three other greenhouse gases. Part 2 estimates trends and projections for methane (CH_4) emissions. In the 1990 baseline year, livestock operations emitted about 10.4 million tons (STCDE) of methane (CH_4) and landfills emitted about 5.5 million tons (STCDE). Together, these two sources accounted for more than 95 percent of Missouri's CH_4 emissions.

[1] Throughout this chapter, the unit of measure is short tons carbon dioxide equivalent (STCDE) unless otherwise specified. As explained in Chapter 1, this unit of measure functions to permit comparisons between different greenhouse gases. For example, 1 million tons STCDE of methane, released into the atmosphere, is expected to have an effect on average temperature equivalent to the effect of releasing 1 million tons of CO_2.

Part 3 estimates trends and projections for nitrous oxide (N_2O) emissions. Agriculture is the leading source of N_2O emissions, just as it is the leading source of methane emissions. The *1990 Inventory* found that in the baseline year use of nitrogenous fertilizers accounted for more than 60 percent of Missouri's CH_4 emissions. Most of the remaining N_2O emissions originate in the transportation sector or with industrial manufacture of nitric acid.

Finally, Part 4 estimates trends and projections for emissions of perfluorinated carbons (PFCs), for which aluminum production is the sole source. Operations at Missouri's sole aluminum plant were the source of about 4.6 million tons (STCDE) of PFCs in 1990. Improvements in processes at the plant resulted in a decrease in PFC emissions of nearly 4 million tons (STCDE) between 1990 and 1996. Table 1 summarizes trends in emissions covered by this chapter. Table 2 summarizes projections of these emissions through 2015.

Table 1 - Estimated trend of GHG emissions from Missouri sources other than fossil fuel combustion, 1990-96

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1991	1992	1993	1994	1995	1996
CO_2 emissions excluding energy	11,656	10,998	11,349	10,983	11,504	11,326	11,872
Oxidation of carbon monoxide	1,460	1,433	1,481	1,516	1,570	1,595	1,650
Transportation	1,293	1,279	1,325	1,349	1,396	1,424	1,477
Industrial sector	168	153	156	167	173	171	173
Non-energy uses of fossil fuels	1,345	849	951	910	960	946	982
Industrial sector uses	1,111	640	737	693	733	720	754
Transportation use of lubricants	234	210	214	218	227	226	228
Limestone use	4,445	4,309	4,510	4,150	4,568	4,379	4,834
Cement Production	2,260	2,156	2,382	2,255	2,629	2,424	2,562
Lime Manufacture	1,599	1,597	1,579	1,374	1,413	1,413	1,731
Decomposition of agricultural lime	586	555	549	522	526	541	541
Land use changes	4,407	4,407	4,407	4,407	4,407	4,407	4,407
Net loss of above-ground "sinks"	1,613	1,613	1,613	1,613	1,613	1,613	1,613
Soil carbon release	2,793	2,793	2,793	2,793	2,793	2,793	2,793
Methane emissions	16,712	16,762	17,056	17,569	18,343	18,159	18,290
Agriculture	10,463	10,255	10,410	10,796	11,445	11,140	11,166
Beef cattle operations	5,677	5,634	5,772	5,933	6,288	5,956	6,161
Dairy cattle operations	1,808	1,766	1,701	1,686	1,605	1,552	1,477
Swine operations	2,747	2,623	2,705	2,946	3,321	3,401	3,296
Other livestock operations	170	170	170	170	170	170	170
Rice cultivation	61	61	61	61	61	61	61
Disposal of crop wastes by burning	0	0	0	0	0	0	0
Municipal & industrial waste	5,604	5,851	5,997	6,135	6,261	6,375	6,481
Municipal & industrial landfills	5,501	5,748	5,895	6,032	6,158	6,273	6,378
Municipal waste water treatment	103	103	103	103	103	103	103
Fossil fuel production & distribution	501	513	506	495	494	501	501
Natural gas leakage	496	507	500	490	488	495	495
Coal mining	6	6	6	6	6	6	6
Oil production	0	0	0	0	0	0	0
Highway transportation	143	143	143	143	143	143	143
Nitrous oxide emissions	3,805	3,859	3,925	4,001	3,877	3,855	3,820
Agriculture	2,333	2,388	2,454	2,530	2,406	2,383	2,348
Use of nitrogenous fertilizers	2,333	2,388	2,454	2,530	2,406	2,383	2,348
Disposal of crop wastes by burning	0	0	0	0	0	0	0
Highway transportation	1,080	1,080	1,080	1,080	1,080	1,080	1,080
Nitric acid production	391	391	391	391	391	391	391
PFCs from aluminum production	4,611	1,431	1,090	1,157	1,049	1,065	641
CF_4 emissions*	3,847	1,194	910	965	875	889	535
C_2F_6 emissions*	763	237	181	192	174	176	106
****See Part 4.***							
All sources except fossil fuel combustion	***5,317***	***5,318***	***5,319***	***5,320***	***5,321***	***5,322***	***5,323***

Table 2 - Estimated GHG emissions from Missouri sources other than fossil fuel combustion, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

Gross non-energy sources *(excluding forests)*	36,784	33,050	33,420	33,710	34,773	34,405	34,623
	1990	**1996**	**2000**	**2005**	**2010**	**2015**	**Change**
CO_2 emissions excluding energy	11,656	11,872	12,169	12,595	12,984	13,357	1,701
Oxidation of carbon monoxide	1,460	1,650	1,733	1,810	1,857	1,877	417
Transportation	1,293	1,477	1,549	1,616	1,653	1,662	369
Industrial sector	168	173	184	194	204	215	48
Non-energy uses of fossil fuels	1,345	982	1,036	1,074	1,120	1,171	(173)
Industrial sector uses	1,111	754	803	835	875	920	(191)
Transportation use of lubricants	234	228	233	239	245	251	17
Limestone use	4,445	4,834	4,994	5,304	5,600	5,902	1,458
Cement Production	2,260	2,562	2,804	3,106	3,408	3,710	1,450
Lime Manufacture	1,599	1,731	1,731	1,731	1,731	1,731	132
Decomposition of agricultural lime	586	541	459	468	462	462	(124)
Land use changes	4,407	4,407	4,407	4,407	4,407	4,407	0
Net loss of above-ground "sinks"	1,613	1,613	1,613	1,613	1,613	1,613	0
Soil carbon release	2,793	2,793	2,793	2,793	2,793	2,793	0
Methane emissions	16,712	18,290	16,472	17,185	16,861	16,557	(155)
Agriculture	10,463	11,166	10,796	11,234	11,068	11,023	560
Beef cattle operations	5,677	6,161	5,636	6,074	6,210	6,420	744
Dairy cattle operations	1,808	1,477	1,238	1,023	852	700	(1,108)
Swine operations	2,747	3,296	3,691	3,906	3,776	3,672	925
Other livestock operations	170	170	170	170	170	170	0
Rice cultivation	61	61	61	61	61	61	0
Disposal of crop wastes by burning	0	0	0	0	0	0	0
Municipal & industrial waste	5,604	6,481	5,033	5,307	5,149	4,890	(714)
Municipal & industrial landfills	5,501	6,378	4,930	5,205	5,046	4,788	(714)
Municipal waste-water treatment	103	103	103	103	103	103	0
Fossil fuel production & distribution	501	501	501	501	501	501	(1)
Natural gas leakage	496	495	495	495	495	495	(1)
Coal mining	6	6	6	6	6	6	0
Oil production	0	0	0	0	0	0	0
Highway transportation	143	143	143	143	143	143	0
Nitrous oxide emissions	3,805	3,820	3,875	3,872	3,870	3,868	63
Agriculture	2,333	2,348	2,403	2,401	2,399	2,397	63
Use of nitrogenous fertilizers	2,333	2,348	2,403	2,401	2,399	2,397	63
Disposal of crop wastes by burning	0	0	0	0	0	0	0
Highway transportation	1,080	1,080	1,080	1,080	1,080	1,080	0
Nitric acid production	391	391	391	391	391	391	0
PFCs from aluminum production	4,611	641	650	458	437	416	(4,194)
CF_4 emissions*	3,847	535	542	382	365	347	(3,500)
C_2F_6 emissions*	763	106	108	76	72	69	(694)

See Part 4.

Greenhouse gas emissions from the sources covered by this chapter are projected to decline by about 2.5 million tons (STCDE), an average annual rate of decline of 0.3 percent. However, this overall statistic masks the different roles played by different sources over time.

Emissions from three sources are projected to decrease by a total of about 6 million tons (STCDE); PFC emissions (4.2 million tons), methane emissions from dairy operations (1.1 million tons) and methane emissions from landfills (0.7 million tons). However, the decrease in PFC emissions occurred early in this period, whereas the decrease in landfill emissions is projected to occur after the year 2000.

Emissions from three other sources are expected to increase by a total of 1.1 million tons (STCDE); primarily methane emissions from beef and swine operations (1.7 million tons) and CO_2 emissions from cement and lime manufacture (1.4 million tons). Emissions from all other sources covered in this chapter are projected to increase by about 0.4 million tons.

These overall statistics mask the very different roles that methane sources played in 1990 through 1996 and that they are projected to play in 1996 through 2015. During 1990 through 1996, when the decrease in overall emissions was driven by PFC emissions, increases in methane emissions offset a portion of this decrease. During this period, methane from landfills increased by about 0.9 million tons (STCDE) and methane from swine and beef operations increased by about 1 million tons (STCDE). Methane from dairy operations decreased by about 0.3 million tons (STCDE).

During 1996 through 2015, decreases in methane sources are projected to drive the decrease in overall emissions. Methane emissions from landfills are projected to decrease by 1.6 million tons (STCDE). Methane emissions from livestock operations are also projected to decrease, with a 0.6 million ton increase in methane emissions from swine and beef operations being offset by a 0.8 million ton decrease from dairy operations. These decreases are expected to occur due to an increase in the flaring and capture of landfill methane, a slowdown in the growth of swine operations in Missouri and continued decline of the state's dairy industry.

Table 3 summarizes the average annual rate of growth for sources of greenhouse gas covered in this chapter.

Table 3 - Annual average rate of growth for sources other than fossil fuel combustion, 1990-1996, 1996-2015 and 1990-2015

	1990-1996	1990-2015	1996-2015
CO_2 emissions excluding energy	0.3%	0.5%	0.6%
Oxidation of carbon monoxide	2.1%	1.0%	0.7%
Transportation	2.3%	1.0%	0.6%
Industrial sector	0.5%	1.0%	1.2%
Non-energy uses of fossil fuels	-5.1%	-0.6%	0.9%
Industrial sector uses	-6.2%	-0.8%	1.1%
Transportation use of lubricants	-0.5%	0.3%	0.5%
Limestone use	1.4%	1.1%	1.1%
Cement Production	2.1%	2.0%	2.0%
Lime Manufacture	1.3%	0.3%	0.0%
Decomposition of agricultural lime	-1.3%	-0.9%	-0.8%
Methane emissions	1.5%	0.0%	-0.5%
Agriculture	1.1%	0.2%	-0.1%
Beef cattle operations	1.4%	0.5%	0.2%
Dairy cattle operations	-3.3%	-3.7%	-3.9%
Swine operations	3.1%	1.2%	0.6%
Municipal & industrial waste	2.5%	-0.5%	-0.3%
Municipal & industrial landfills	2.5%	-0.6%	-0.3%
Nitrous oxide emissions	0.1%	0.1%	0.1%
Agriculture	0.1%	0.1%	0.1%
Use of nitrogenous fertilizers	0.1%	0.1%	0.1%
PFCs from aluminum production	-28.0%	-9.2%	-2.2%
CF_4 emissions*	-28.0%	-9.2%	-2.2%
C_2F_6 emissions*	-28.0%	-9.2%	-2.2%

See Part 4.

Part 1: CO_2 emissions from sources other than fossil fuel combustion — trends and projections

Although fossil fuel combustion is the most important source of CO_2 emissions in Missouri, the *1990 Inventory* identified several additional sources of CO_2 emissions in the state. CO_2 emissions from these additional sources are projected to increase at a modest 0.5 percent annual growth rate from 1990 to 2015.

Through 2015, CO_2 emissions from Missouri cement manufacture are projected to increase by about 1.5 million tons per year. Otherwise, the projected changes in emissions from these sources are minor when compared to the magnitude of projected increases from energy use.

Section 1 presents trends and projections for oxidation of carbon monoxide (CO). CO is emitted as a byproduct of energy use in industry and transportation. Although CO is not a greenhouse gas, it oxidizes into CO_2 within a year.

Section 2 presents trends and projections for non-energy uses of fossil fuels. Petroleum and natural gas are used in some manufacturing processes that do not involve combustion but still lead to CO_2 emissions. The CO_2 emissions typically are lower than would have occurred if the fossil fuel were burned, since some carbon remains sequestered in the product.

Section 3 presents trends and projections for CO_2 emissions that result from a variety of agricultural and industrial uses of limestone, including cement manufacture.

A final source of CO_2 emissions is changes in land use. Some land use changes, such as conversion of forest land to other uses, reduce the ability of land to sequester carbon and are therefore sources of net CO_2 emissions. Other land use changes, such as permitting an agricultural field to revert to forest, may increase sequestration.

Chapter 7 of the *1990 Inventory* estimated changes in above-ground and below-ground carbon from land use changes using data gathered by the Natural Resource Conservation Service during its 1980 and 1990 Missouri Natural Resource Inventory surveys. Because no subsequent inventory has occurred, no data is available to revise the estimates presented in the *1990 Inventory*. Therefore, in estimating the 1990 to 1996 trends and the 1990 to 2015 projections, this study assumes that CO_2 emissions from land use changes estimated for 1990 will continue annually through 2015.

Section 1: CO_2 emissions from oxidation of carbon monoxide

Chapter 2 of the *1990 Inventory* sets out the methodology and rationale for including oxidation of carbon monoxide in the transportation and industrial sectors as a source of CO_2. The resulting trends and projections, summarized in Tables 4 and 5, assume that carbon monoxide emissions in the transportation sector will increase at the same rate as projected gasoline and diesel use in that sector, and that industrial CO_2 emissions from this source will increase at the same rate as industrial primary fossil fuel use.

The resulting trend and projection estimates are as follows.

Table 4 - Trends in estimated CO_2 emissions from oxidation of CO in Missouri, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996
Oxidation of carbon monoxide	1,460	1,433	1,481	1,516	1,570	1,595	1,650
Transportation	1,293	1,279	1,325	1,349	1,396	1,424	1,477
Industrial	168	153	156	167	173	171	173

Table 5 - Projections of estimated CO_2 emissions from oxidation of CO in Missouri, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1996	2000	2005	2010	2015
Oxidation of carbon monoxide	1,460	1,650	1,733	1,810	1,857	1,877
Transportation	1,293	1,477	1,549	1,616	1,653	1,662
Industrial sector	168	173	184	194	204	215

As described in Chapter 4, the estimated growth rates for primary fossil fuel consumption in the transportation and industry sectors depend on the estimation method. The projections shown in Table 5 are based on the AEO method for projecting transportation and industry fossil fuel combustion.

As Table 6 indicates, the projection of carbon monoxide from the transportation sector would increase if it were based on the SS and CT methods for projecting energy use because these methods project faster transportation energy growth than the *Annual Energy Outlook 1997*. The Energy Information Administration, which produces the *Annual Energy Outlook*, has also revised its gasoline use projections upward from those that appear in the *Annual Energy Outlook 1997*. On the other hand, the projection for the industrial sector is larger than it would be using the CT projection method.

Table 6 - Comparison of CT, SS and AEO projections of Missouri GHG emissions from oxidation of CO in 2015

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	CT	SS	AE
Oxidation of Carbon Monoxide	2,039	1,982	1,877
Transportation	1,913	1,732	1,662
Industrial	126	250	215

Section 2: CO_2 emissions from non-energy uses of fossil fuels

In Missouri, lubricants and a portion of natural gas, LPG and "other petroleum products"[2] are used for non-energy purposes in the transportation and industrial sectors. Table 7 summarizes the *1990 Inventory* estimates for the portion of each fuel going to non-energy uses in 1990. To expedite the process of estimating non-energy related emissions from these sources between 1991 and 2015, the study assumes the proportion of each fuel used for non-energy purposes remains constant at the 1990 level through 2015.

Combustion of fossil fuels for energy leads to the oxidation of nearly all the carbon in the fuel. In non-energy uses of fossil fuels, however, a large portion of the carbon is frequently sequestered rather than oxidized. This study takes from the *1990 Inventory* the following estimates of the percentage of carbon sequestration in non-energy uses of fossil fuels:

- 50 percent of transportation lubricants;
- 50 percent of industrial lubricants, natural gas and petroleum coke; and
- 80 percent of industrial LPG, naptha (> 104F) and other oils (<104F).

A CO_2 emissions multiplier for non-energy use was determined for each of these fuels based on the estimated carbon content and level of sequestration for each fuel. Table 7 summarizes these multipliers.

Table 7 - Parameters for estimating CO_2 emissions from non-energy uses of fossil fuels

	Non-Energy Use as Percentage of Total Use		CO_2 Emissions Multiplier
	Transportation	Industrial	
Lubricants	100%	100%	80.9
Natural gas	N/A	4.1%	2.4
LPG	N/A	1.7%	0.5
Other petroleum	N/A	67%	31.9

When the coefficients in Table 7 are applied to consumption estimates and projections for the fossil resources listed in Table 7 for 1991-2015, the resulting estimates of CO_2 emissions from non-energy use are as follows:

[2] These fuels are defined in Appendix A of the USDOE/EIA *State Energy Data Report*, which adopts the standard reporting categories of its federal and industry data sources. The fossil fuels included as "other petroleum products" include naptha (>104˚F), other oils (<104˚F), pentanes plus, special naptha, waxes, petroleum coke and "miscellaneous petroleum products."

Table 8 - Trends in estimated CO_2 emissions from non-energy uses of fossil fuels

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996
Industry							
Lubricants	168.53	150.77	153.72	156.52	163.60	162.76	163.67
Natural gas	65.74	68.79	69.85	73.00	85.90	82.57	83.77
LPG	1.54	1.73	1.58	2.19	2.17	2.10	2.37
Other petr.	874.73	418.56	511.99	461.01	481.07	472.17	504.37
Subtotal	1,110.55	639.85	737.13	692.73	732.74	719.60	754.17
Transportation	234.32	209.63	213.73	217.63	227.46	226.30	227.56
Total	***1,344.88***	***849.48***	***950.86***	***910.36***	***960.20***	***945.90***	***981.73***

Table 9 - Projections of CO_2 emissions from non-energy uses of fossil fuels in 2005

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Industry						
Lubricants	168.53	162.76	167.28	171.79	176.30	180.82
Natural gas	65.74	82.57	93.33	98.77	104.74	108.76
LPG	1.54	2.10	2.23	2.55	2.87	3.31
Other petr.	874.73	472.17	540.18	562.24	591.12	627.11
Subtotal	1,110.55	719.60	803.01	835.36	875.04	919.99
Transportation	234.32	226.30	232.58	238.85	245.13	251.40
Total	***1,344.88***	***945.90***	***1,035.59***	***1,074.21***	***1,120.17***	***1,171.39***

As explained in Chapter 2, the 1990 and 1991 decline in "other petroleum" reported in these tables is partly an artifact of a change in USDOE/EIA reporting procedures.

Section 3: CO_2 emissions from agricultural and industrial uses of limestone

Agricultural and industrial uses of limestone were included as a source of CO_2 emissions in the *1990 Inventory*. The methodology and rationale for inclusion are summarized in the Methodological Appendix to Chapter 5.

Agricultural lime is applied with the intention that it will decompose into calcium and various byproducts including CO_2. By Missouri law, agricultural lime must be at least 65 percent calcium carbonate ($CaCO_3$).

The rate of decomposition of agricultural lime varies depending on its mesh (size) and other factors. Use of a 10-year average for application of agricultural lime is sufficient to remove rate of decomposition as an issue in estimating emissions. For example, in order to estimate CO_2 emissions in 1990, data for the years 1981 to 1990 is used to determine the average rate of application over the previous 10 years.

Missouri agricultural lime usage data between 1981 and 1997[3] was obtained from Fertilizer Control Services (FCS), Agricultural Experiment Station, University of Missouri-Columbia. It was assumed that Missouri farmers would continue to apply agricultural lime during 1998 through 2015 at the rate of 1,614,673 tons per year, the average rate of application between 1990 and 1997 calculated from the FCS data. The FCS usage data was used to estimate the 10-year averages for 1990 to 1996 in Table 10. Similarly, 10-year averages were calculated for all subsequent years. Lower-bound estimates of $CaCO_3$ for 1990 to 1996 are shown in Table 10; lower-bound estimates for future years are shown in Table 11. These are estimated by multiplying 10-year average use estimates by 65 percent. The resulting CO_2 emissions are estimated by multiplying estimated $CaCO_3$ by 44/100, the ratio of the molecular weight of CO_2 to $CaCO_3$.

Table 10 - Trend of estimated CO_2 emissions from agricultural lime use in Missouri, 1990-96

Units: Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996
FCS agric. lime data	1,708,651	1,482,467	1,631,184	1,083,952	1,648,914	1,927,803	1,804,151
Ten-year average	2,048,967	1,940,704	1,918,412	1,824,067	1,839,440	1,892,758	1,911,824
Lower bound $CaCO_3$	1,331,829	1,261,457	1,246,968	1,185,644	1,195,636	1,230,293	1,242,686
Lower bound CO_2	586,005	555,041	548,666	521,683	526,080	541,329	546,782

[3] Estimates for 1997 were received while the draft report was undergoing final review and were incorporated into the emissions estimates shown here.

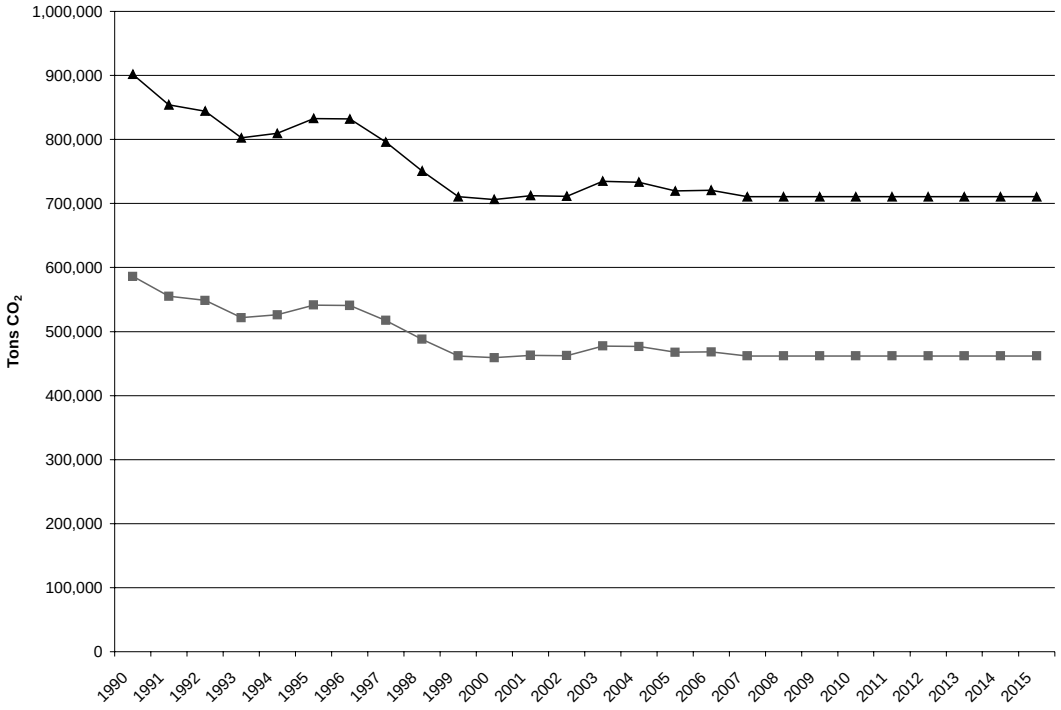
Table 11 - Projections of estimated CO_2 emissions from agricultural lime use in Missouri, 1990-2015

Units: Tons Carbon Dioxide (CO_2)

	1990	2000	2005	2010	2015
Lower bound $CaCO_3$	1,331,829	1,043,429	1,062,867	1,049,538	1,049,538
Lower bound CO_2	586,005	459,109	467,661	461,797	461,797

As Chart 1 indicates, use of the lower bound of CO_2 emissions from agricultural lime use provides a conservative estimate of CO_2 emissions from this source. The upper bound illustrated in Chart 1 represents estimated emissions if 100 percent of the agricultural lime applied consists of calcium carbonate. The actual calcium carbonate content of most agricultural lime applied in Missouri is probably greater than 65 percent. However, the lower bound of 65 percent is used for trends and projections estimates in this report to compensate for the possibility that some calcium carbonate is leached or enters chemical pathways that do not result in CO_2 emissions.

Chart 1 - Upper and lower bounds of estimated CO_2 emissions from agricultural lime use in Missouri, 1990-2015



Industrial uses of limestone include cement manufacture and lime manufacture, uses which lead to the chemical decomposition of calcium carbonate and the release of CO_2.

The primary release of CO_2 during cement production occurs in the manufacture of clinker. About 97 percent of the cement manufactured in Missouri in 1990 was Portland cement; the remaining 3 percent was masonry cement. Clinker is the only source of CO_2 emissions in the manufacture of Portland cement. The production of masonry cement involves the addition of lime beyond that contained in clinker.

Data on Missouri cement and lime production from 1990 to 1996 were obtained from the Division of Mineral Commodities (DMC) of the U.S. Department of Interior's Bureau of Mines. Production of Portland cement between 1997 and 2015 was projected by linear regression on the 1990 to 1996 data. Missouri clinker production for the years after 1990 was estimated assuming that the ratio of clinker to Portland cement would remain constant at the 1990 ratio.

Table 12 summarizes the DMC data as well as trend estimates, and Table 13 summarizes the corresponding projections through 2015. The analysis assumes that production of masonry cement remains constant after 1990 (approximately 127,000 tons).

Table 12 - Trends in cement and clinker production in Missouri, 1990-96

Units: Tons

	1990	1991	1992	1993	1994	1995	1996
Cement production	4,481,000	4,276,000	4,724,501	4,472,072	5,213,926	4,808,276	5,082,402
Clinker production	4,451,000	4,247,372	4,692,871	4,442,132	5,179,019	4,776,085	5,048,376
Masonry cement	127,000	127,000	127,000	127,000	127,000	127,000	127,000
Lime production	2,037,000	2,035,000	2,012,000	1,750,000	1,800,000	1,800,000	2,204,620

Table 13 - Projected cement and clinker production in Missouri through 2015

Units: Tons

	1990	2000	2005	2010	2015
Cement production	4,481,000	5,562,143	6,161,818	6,761,494	7,361,169
Clinker production	4,451,000	5,524,904	6,120,565	6,716,226	7,311,887
Masonry cement	127,000	127,000	127,000	127,000	127,000

The estimation methodology for industrial emissions uses the following emissions coefficients to estimate CO_2 emissions per ton of clinker, masonry cement or lime produced:

Table 14 - Emissions coefficients per ton of clinker, masonry cement or lime

	Tons CO_2 per ton production
Clinker production	0.507
Masonry cement	0.0224
Lime production	0.785

Use of these coefficients results in the trend estimates summarized in Table 15 and projection estimates summarized in Table 16. The projected growth in CO_2 emissions is due primarily to an expected increase in cement production.

Table 15 - Estimated CO_2 emissions from industrial and agricultural use of limestone, 1990-96

Units: Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996
Clinker production	2,256,657	2,153,418	2,379,285	2,252,161	2,625,763	2,421,475	2,559,526
Masonry cement	2,845	2,845	2,845	2,845	2,845	2,845	2,845
Lime production	1,599,045	1,597,475	1,579,420	1,373,750	1,413,000	1,413,000	1,730,627
Agricultural lime	586,005	555,041	548,666	521,683	526,080	541,329	540,679

Table 16 - Projected CO_2 emissions from industrial and agricultural use of limestone through 2015

Units: Tons Carbon Dioxide (CO_2)

	1990	2000	2005	2010	2015
Clinker production	2,256,657	2,801,127	3,103,127	3,405,127	3,707,127
Masonry cement	2,845	2,845	2,845	2,845	2,845
Lime production	1,599,045	1,730,627	1,730,627	1,730,627	1,730,627
Agricultural lime	586,005	459,109	467,661	461,797	461,797
Total	4,444,551	4,993,707	5,304,259	5,600,395	5,902,395
Growth rate		***1.2%***	***1.2%***	***1.2%***	***1.1%***

Part 2: Methane emissions — trends and projections

The *1990 Inventory* identified two major sources of anthropogenic methane emissions in Missouri — agricultural sources, particularly methane emissions from livestock and waste disposal in municipal and industrial landfills, together accounting for more than 95 percent of methane emissions. The only other significant source was leakage from natural gas pipelines, which contributed an estimated 3 percent of methane emissions in 1990. The remaining 1 percent of anthropogenic methane emissions originated from transportation, oil production and coal mining.

This study estimates trends in the agricultural and landfill sources of methane emissions between 1990 and 1996 and projects emissions from these sources between 1996 and 2015. It assumes that methane emissions from other sources have remained constant since 1990.

Table 17 summarizes trend estimates for Missouri methane emissions between 1990 and 1996, and Table 18 summarizes projections through 2015. In all cases, STCDE estimates were derived by applying the Global Warming Factor (GWF) of 24.5 STCDE per ton of CH_4.

Table 17 - Estimated methane emissions in Missouri, 1990-96

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1991	1992	1993	1994	1995	1996
Agriculture	10,463	10,255	10,410	10,796	11,445	11,140	11,166
Beef cattle	5,677	5,634	5,772	5,933	6,288	5,956	6,161
Dairy cattle	1,808	1,766	1,701	1,686	1,605	1,552	1,477
Swine	2,747	2,623	2,705	2,946	3,321	3,401	3,296
Other livestock	170	170	170	170	170	170	170
Rice cultivation	61	61	61	61	61	61	61
Burning crop wastes	0	0	0	0	0	0	0
Municipal waste	5,419	5,633	5,738	5,836	5,922	5,999	6,066
Municipal & industrial landfills	5,316	5,530	5,636	5,733	5,820	5,896	5,964
Municipal waste water treatment	103	103	103	103	103	103	103
Fossil fuel prod'n & dist'n	501	513	506	495	494	501	501
Natural gas leakage	496	507	500	490	488	495	495
Coal mining	6	6	6	6	6	6	6
Oil production	0	0	0	0	0	0	0
Highway transportation	143	143	143	143	143	143	143
Total	***16,527***	***16,544***	***16,797***	***17,270***	***18,005***	***17,783***	***17,876***

Table 18 - Projected methane emissions in Missouri, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1996	2000	2005	2010	2015
Agriculture	10,463	11,166	10,796	11,234	11,068	11,023
Beef cattle	5,677	6,161	5,636	6,074	6,210	6,420
Dairy cattle	1,808	1,477	1,238	1,023	852	700
Swine	2,747	3,296	3,691	3,906	3,776	3,672
Other livestock	170	170	170	170	170	170
Rice cultivation	61	61	61	61	61	61
Burning crop wastes	0	0	0	0	0	0
Municipal waste	5,604	6,481	5,033	5,307	5,149	4,890
Municipal & industrial landfills	5,501	6,378	4,930	5,205	5,046	4,788
Municipal waste water treatment	103	103	103	103	103	103
Fossil fuel prod'n & dist'n	501	501	501	501	501	501
Natural gas leakage	496	495	495	495	495	495
Coal mining	6	6	6	6	6	6
Oil production	0	0	0	0	0	0
Highway transportation	143	143	143	143	143	143
Total	***16,712***	***18,290***	***16,472***	***17,185***	***16,861***	***16,557***

Section 1: Methane emissions from municipal and industrial landfills

Landfills are the most concentrated source of anthropogenic methane emissions in Missouri. More methane is emitted from livestock operations than landfills, but most of these operations are relatively small and spread widely across the state. This study estimates that in 1990, Missouri's sanitary and industrial landfills produced about 263,000 tons (STCDE) of methane;[4] by comparison, livestock operations produced about 426,000 tons (STCDE) of methane.

Methane production from Missouri landfills has increased every year since 1990. The increase is projected to continue until methane production peaks in the year 2006. The projected increase is based on the assumption that waste, once placed in a landfill, continues to generate methane for about 30 years. As documented in the *1990 Inventory*, large sanitary landfills are a relatively recent phenomenon in Missouri. Since nearly all the waste in Missouri's landfills has been placed there since 1976, it follows that this waste will continue to generate methane through at least 2006 and that annual additions of new waste will lead to an increase in annual emissions.

After about 2006, annual methane production from Missouri's landfills is projected to decrease. This reflects reductions in annual landfill waste receipts that have occurred after 1991 following passage of legislation in 1990 that set waste reduction goals, as well as the transition of waste that is over 30 years old from a methanogenically active stage to a "stabilized" stage in which emissions have ceased.

This study projects that Missouri landfills will produce about 347,000 tons (STCDE) of methane in the year 2006 and 324,000 tons (STCDE) in the year 2015. These are midpoint estimates. The corresponding range estimates are 277,000 to 417,000 tons (STCDE) in 2006 and 256,000 to 391,000 tons (STCDE) in 2015. The wide range of these estimates reflect uncertainty about the projected waste-in-place in landfills as well as uncertainties related to the estimation model itself.

Regardless of the accuracy of these projections, it is likely that methane production will increase until the year 2006 and then decrease through 2015. However, this pattern could be affected by waste exports. Missouri's two largest metropolitan areas are located at state borders with Kansas and Illinois, and a significant portion of the waste generated in these metropolitan areas crosses state lines. In recent years, Missouri has exported approximately one-third of its solid waste. A decrease in the net flow of waste from Missouri to bordering states could result in an increase in landfill receipts and methane generation even if the per capita rate of waste is decreasing and the rate of recovery or recycling is increasing in Missouri. Similarly, an increase in waste export could reduce receipts and methane generation in Missouri landfills. Since future waste export rates are dependent on many local factors and inherently difficult to project, this study assumes that exports will continue at the present level.

[4] This is the average of the estimated range for gross potential landfills methane emissions in 1990, 183,000 to 343,000 tons (STCDE). The corresponding range estimate for 2006 is 277,000 to 417,000 tons (STCDE), and for 2015 is 256,000 to 391,000 tons (STCDE).

Net methane emissions from Missouri landfills are lower than the *production* of methane because some methane produced by landfills is oxidized before reaching the surface, and some that reaches the surface is flared or recovered instead of entering the atmosphere. For example, if all the methane produced by Missouri landfills in 1990 had entered the atmosphere, emissions equal to about 6.4 million tons (STCDE) would have occurred. Because some methane was oxidized, flared or captured, only about 5.5 million tons (STCDE) of methane entered the atmosphere.

Although methane production is projected to peak in 2006, net methane emissions are projected to peak in 1999. The projected decrease in net emissions is due to an increase in methane flaring and capture that is expected to occur as a result of federal and state regulations that require some Missouri landfills to develop landfill gas collection systems by the year 2000.[5]

This study projects that net methane emissions will equal about 6.7 million tons (STCDE) in 1999, 4.9 million tons (STCDE) in 2000, 5.2 million tons (STCDE) in 2006 and 4.8 million tons (STCDE) in 2015. At no point between 2000 and 2015 are net emissions expected to reach their 1990 level.

Regardless of the accuracy of these projections, it is likely that net methane emissions will peak in the year 1999, decrease to below 1990 levels in the year 2000, gradually increase again until 2006, and then decrease through 2015. However, this pattern could be affected by landfill operator decisions in response to federal regulations or opportunities to invest in methane capture. For example, net emissions could be higher if landfill operators delay their compliance with federal and state regulations, or lower than projected if landfill operators decide to invest in methane capture beyond the requirements of these regulations. Since these decisions are inherently unpredictable, it is assumed that operators will meet but not exceed federal and state requirements.

This study's estimates of landfill methane emissions, like estimates in the *1990 Inventory*, are calculated using a statistical estimation model prescribed by the U.S. Environmental Protection Agency (USEPA) in its *States Workbook*. The model provides equations to estimate the *potential gross emissions* from large and small municipal landfills based on estimated waste-in-place (WIP) in these landfills. Potential gross emissions from industrial landfills are estimated based on the municipal landfill estimates. Finally, the estimates of potential gross emissions are discounted to account for oxidation, flaring and capture.

[5] *Federal Register,* Vol. 61, No. 49, p. 9905, March 12, 1996. The Missouri Air Pollution Control Program is publishing regulations for St. Louis and the remainder of the state that affect some landfills not covered by the federal regulation. The regulations are intended to control non-methane organic compounds (NMOCs) but the systems to collect and dispose of NMOCs are expected to remove methane as well; USEPA, *Greenhouse Gas Emissions from Municipal Waste Management, Draft Working Paper*, March 1997, Chapter 7.

The USEPA's statistical model is based on USEPA research completed by the Air and Energy Engineering Research Laboratory (AAERL) in 1991 and the Office of Air and Radiation (OAR) in 1993. The purpose of the AAERL study[6] was to determine whether a simple statistical model based on physical characteristics of landfills could be used to estimate methane emissions from landfills at an aggregate (global or national) level. Using data from a sample of 21 landfills, the AAERL study tested the statistical relationship between methane emissions and a number of variables assumed to affect emissions from landfills.[7] Although a number of factors were correlated with emissions, the study concluded that waste-in-place explained the largest portion of the observed variation in emissions and that a simple model relating emissions to total amount of waste-in-place is adequate for estimating methane production.

Drawing on the AAERL study, the OAR study[8] used linear regression to estimate the relationship between methane emissions and waste-in-place in large U.S. landfills. To estimate the relationship, the study used data for 85 U.S. landfills with over 1.1 million tons of waste-in-place, drawn from a database of landfills with methane collection systems. From discussions with industry experts, the analysts concluded that these 85 landfills are representative of large landfills generally. Although the analysts understood that many factors can influence landfill emissions, they argued that "since [these 85 landfills] vary in depth, age, regional distribution and other factors … a simple model based [on data for these landfills] should provide a robust estimate of methane emissions from landfills."

The OAR study developed a second equation to estimate emissions from small landfills based on the average methane generation rate for the 85 large landfills in the database. The study used the large landfill data rather than small landfill data in the database because the small landfills included in the database were "gassier" than average. The study acknowledged that this method implicitly assumes that "with the exception of size, the relevant characteristics of small landfills are similar to the characteristics of the larger landfills in the data set."

This background is necessary in order to understand that there are several sources of uncertainty and possible error in this study's emissions estimates. Some derive from assumptions made by the AAERL/OAR model. Others are associated with the task of estimating or projecting the waste-in-place data that is required by the model.

1. The simplicity of the AAERL/OAR model raises the issue whether it is properly specified. As acknowledged in both the AAERL and OAR studies, many factors related to climate, characteristics of the waste and characteristics of the design and operation of a landfill may affect methane generation. However, it must be recognized that the intended use of the model is to estimate emissions at an aggregate (national or global) level. For tasks such as assessing the feasibility of capturing methane at an individual site, USEPA recommends that other models be used.[9]

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[6] Peer, Rebecca L., et. al., *Development of an Empirical Model of Methane Emissions from Landfills*, EPA-600/R-92-037, March 1992.

[7] Variables tested in addition to waste-in-place included climate; refuse characteristics such as moisture content, composition, age and pH; landfill characteristics such as age, depth, volume and surface area; and waste-handling practices.

[8] USEPA/OAR, *Anthropogenic Methane Emissions in the United States: Estimates for 1990: Report to Congress*,1993.

[9] Personal communication, Susan Thornloe, USEPA, October 1, 1998. One recommended model is LandGEM.

The AAERL study concluded that waste-in-place explains a sufficient portion of the variation in landfill emissions to serve as the basis for a model intended to estimate emissions across an aggregation of landfills. However, the study tested some but not all of the possible factors and its analytic approach was limited to regression methods conducted on a small sample of only 21 landfills. Therefore, until other studies confirm the AAERL study's results, its conclusions should be considered tentative.

2. As explained in the *1990 Inventory*, the waste sites in Missouri include many landfills that are small by USEPA standards (less than 1.1 million tons of waste-in-place) and also many abandoned town dumps whose methane emissions characteristics are largely unknown. As prescribed by the *States Handbook*, this study uses the AAERL/OAR model to estimate emissions from these sources. However, application of the model to these waste sites is a possible source of error because the AAERL/OAR model was estimated using data from the largest landfills in the U.S. The OAR study concedes that the model does not readily apply to abandoned waste dumps and that the basis for estimating emissions from small landfills needs to be improved."[10] This study's estimates are adjusted in two ways to account for this possible source of error. The estimates for emissions from small landfills are assigned a ±20 percent range of error. In addition, as described in the *1990 Inventory*, the estimates of waste-in-place in town dumps are discounted, with a higher discount rate assigned in the low waste-in-place scenario.

3. Aside from issues of landfill size, there are other bases on which to ask whether the landfills used to estimate the model are representative of landfills in Missouri. The model was developed to estimate emissions at a highly aggregated (global or national) level. When it is applied to estimates at a state level, it is possible that certain variables that "average out" at the global or national level may be significant at a state level. For example, landfills in Missouri are probably younger on average than landfills in the sample database, but the model assumes that the rate of emissions is constant over a 30 year period and for all landfills. Generation rates of methane may vary over time and have been determined to be highest at closure. Moreover, Subtitle D landfills, also known as dry tomb landfills, are drier and decompose more slowly than pre-Subtitle D landfills.

Another example of a variable that may be significant at the state level is average temperature. The emissions coefficients in USEPA's model for state methane emissions from livestock waste are adjusted for average state temperature. A similar adjustment might be appropriate in the model for state landfill emissions.

4. The model assumes that waste deposited in a landfill generates methane for 30 years. Thus, methanogenically active waste-in-place for a landfill for any given year is assumed to be the total of waste placed in the landfill during the previous 30 years. The assumed 30-year time horizon could be an overestimate or underestimate.

5. In Missouri, the percentage of organic material in the municipal waste stream has been reduced since 1990 in response to statutory prohibition against inclusion of yard waste and the increasing market value of waste paper. The model is incapable of incorporating this information because its variables do not include waste stream composition.

[10] ibid., p. 4-34.

6. Estimates of landfill waste-in-place are based on estimates of annual landfill receipts of solid waste. DNR's Solid Waste Management Program began collecting fairly reliable data on landfill receipts in 1990, but there is no reliable data on landfill receipts before 1990. Therefore, estimates of current landfill waste-in-place are subject to error. To account for this source of error, this study continues to use the high waste-in-place and low waste-in-place scenarios described in the *1990 Inventory*.

Future landfill receipts are, by their nature, uncertain. This study extends the high waste-in-place and low waste-in-place scenarios to account for this uncertainty. The scenarios make different assumptions about future population growth, per capita waste generation and waste recycling and recovery. However, these scenarios do assume that waste export rates will remain constant; as previously noted, landfill receipts could be affected by changes in waste export rates.

7. A final source of uncertainty is the relationship between methane generation and net emissions. As the OAR study concedes, the 10 percent average oxidation rate prescribed by the *States Workbook* is based on limited observations and may be too high or too low.[11] In addition, the impact of new federal and state regulations that require certain landfills to develop landfill gas collection systems is uncertain. These regulations are expected to result in an increase in the flaring or capture of methane from Missouri landfills, but to estimate the increase it is necessary to make assumptions about how many landfills will install gas collection systems and about the recovery efficiency for the systems that are installed.

The issues listed above are all significant issues that should be taken into account when assessing the estimates presented in this report. Nevertheless, based on USEPA's review of available alternatives, the methodology recommended by USEPA appears to be the best available to estimate statewide landfill emissions.[12] Development of an alternative methodology is beyond the scope of this project, and any methodology would be subject to many of the sources of uncertainty listed above. Moreover, since other states involved in USEPA projects are also using the methodology recommended by USEPA, its use assures the comparability of estimates for Missouri and other states.

The remainder of this section describes the procedure used to estimate and project methane emissions from Missouri landfills. Two steps are described: estimation of methanogenically active waste-in-place and distribution of waste-in-place between small and large landfills; and application of the USEPA methodology to estimate methane production and net methane emissions.

Step 1: Estimation of methanogenically active waste-in-place (WIP) and distribution of WIP between small and large landfills

Use of the AAERL/OAR model requires an estimate of methanogenically active waste-in-place (WIP) in Missouri landfills. As described in the *1990 Inventory*, WIP for any given year is estimated by aggregating landfill receipts for the previous 30 years.

[11] ibid., p. 4-34.

[12] Although this is the most suitable methodology for estimating statewide emissions, better methodologies are available for estimating emissions from individual landfills.

The *1990 Inventory* develops a model for estimating receipts prior to 1991. This model estimates Missouri landfill receipts as the residual of the amount of waste generated minus the amount of waste going to destinations other than Missouri landfills. Because there are multiple sources of uncertainty about waste generation and disposal before 1990, the *1990 Inventory* develops low-WIP and high-WIP scenarios. The high-WIP scenario estimate for 1990 WIP is about 34 million tons greater than the low-WIP estimate. A large portion of this difference is because the low-WIP scenario heavily discounts receipts of pre-1973 waste, which were deposited primarily in town dumps rather than sanitary landfills. Chapter 3, Section 2 of the *1990 Inventory* describes in detail this and other assumptions and methods used to estimate methanogenically active WIP for years prior to 1991.

Since 1991, Missouri landfill operators have been required by law to report tonnage of waste received. Table 19 summarizes estimates of tonnage received at Missouri landfills between 1991 and 1996. These estimates were aggregated from landfill reports to the Missouri Department of Natural Resources' Solid Waste Management Program (SWMP). Reported landfill receipts decreased nearly 12 percent between 1991 and 1992, and continued to decrease at a decelerating rate that approached 3 percent by 1996. The decrease in receipts between 1990 and 1996 reflects a legislatively mandated effort to reduce the quantity of waste entering Missouri landfills as well as expanded recycling due to an increase in the market value of waste products, especially waste paper.

Table 19 - Estimated aggregate receipts of solid waste at Missouri municipal landfills, 1991-96

Units: 1,000 Short Tons

1991	1992	1993	1994	1995	1996
4,896	4,318	4,157	3,957	3,768	3,624

In order to estimate future methane emissions from landfills, it is necessary to estimate future in-state landfill receipts. Projected receipts are subject to many sources of uncertainty. Table 20 summarizes low-WIP and high-WIP projections of Missouri landfill receipts for selected years from 1997 to 2015.

The low-WIP projection is based on the assumption that Missouri landfill receipts will decrease by 3 percent per year until they reach approximately 50 percent of the 1991 level in 2008 and that after 2008, receipts will remain constant at the 2008 level.[13] The high-WIP projection is based on the assumption that after 1997, per capita waste going to Missouri landfills will remain constant, and landfill receipts will grow at the rate of Missouri population increase.

These assumptions were made to reflect the likely range of variation in factors such as population growth, waste generation rates, recovery and recycling. However, these assumptions do not attempt to anticipate possible changes in patterns of waste export and import. Thus, future receipts could range higher or lower than the projections in Table 20 if there are major changes in the amount of waste moving between Missouri and neighboring states.

[13] Personal communication, Kathy Weinsaft, Missouri SWMP, June 16, 1997.

Table 20 - Projected receipts of solid waste at Missouri municipal landfills, by scenario, 1997-2015

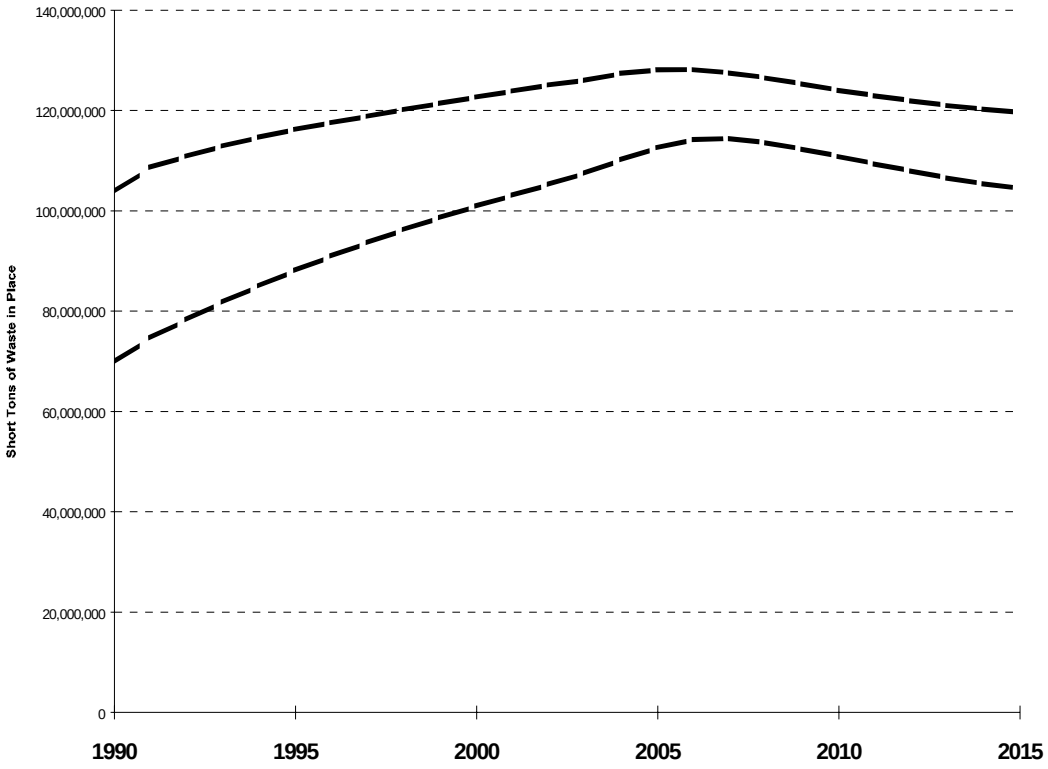
Units: 1,000 Short Tons

	1997	1998	1999	2000	2005	2008	2010	2015
Low WIP	3,515	3,410	3,308	3,208	2,928	2,928	2,928	2,928
High WIP	3,638	3,653	3,667	3,681	3,752	3,796	3,826	3,901

The estimate of aggregate WIP for any given year is estimated as the sum of methanogenically active[14] landfill receipts for the past 30 years. As Chart 2 indicates, the resulting projections indicate that WIP in Missouri's landfills will continue to increase until approximately 2006 despite successful efforts to reduce the waste going in. In 1990, most landfills had no more than 15 years worth of waste. Therefore, as new waste is added between 1990 and 2006, no waste is being "retired" and any additional waste simply increases total WIP. Waste reduction efforts after 2006 do have an impact because, by this time, waste is being retired from methanogenic activity.

[14] The model developed to estimate WIP discounts waste deposited in town dumps through the 1970s because this waste's level of methanogenic activity is uncertain and there is no basis for assuming that the model used to estimate methane emissions accurately estimates methane from waste placed in town dumps.

Chart 2 - Estimated and projected waste-in-place in Missouri landfills, 1990-2015



In addition to an estimate of total WIP, the AAERL/OAR model requires an estimate of the distribution of WIP between small and large landfills. The 1990 Inventory assumed approximately 81 percent of total Missouri WIP was in 17 sanitary landfills qualified as "large" landfills within the AAERL/OAR model, that is, holding at least 1.1 million tons of waste-in-place. Taking this as a starting point, the projection assumes that the number of large landfills will increase to 20 and that after 1990, the percentage of WIP going to large landfills will increase from about 81 percent to about 90 percent. Table 21 summarizes the projected distribution of WIP between large and small landfills.

Table 21 - Projected distribution of WIP between large and small landfills

Units: 1,000 Short Tons

	1990	1995	2000	2005	2010	2015
High-WIP scenario						
Large landfills	84,071	94,341	100,203	105,716	103,986	102,114
Small landfills	19,720	21,885	22,478	22,406	20,051	17,484
Total	103,791	116,226	122,681	128,122	124,037	119,598
Low-WIP scenario						
Large landfills	56,517	71,569	82,987	93,437	92,986	88,565
Small landfills	13,257	16,543	18,491	19,840	18,216	15,552

Step 2: Application of USEPA methodology to estimate methane production

Equations 1 and 2, which are derived from the AAERL and OAR studies discussed previously, are prescribed by the USEPA *States Workbook* to estimate the generation of total statewide methane (CH_4) emissions from large landfills.

Equation 1 — CH_4 emissions from large landfills, high estimate

$$E_{large\text{-}high} = 1.15\ (C_{large}\ W_{landfill}\ P + 419{,}000\ N_{large})$$

Equation 2 — CH_4 emissions from large landfills, low estimate

$$E_{large\text{-}low} = .85\ (C_{large}\ W_{landfill}\ P + 419{,}000\ N_{large})$$

Where:

- C_{large} = emissions factor (cubic feet of CH_4 per ton of waste per day) for large landfills, estimated at .26 ft^3/ton/day
- W = total waste-in-place, defined as total quantity of waste that has been landfilled over the previous 30 years
- P = fraction of WIP placed in large landfills
- N_{large} = number of large landfills, defined as those with at least 1.1 million tons of waste-in-place

The USEPA methodology for estimating total statewide CH_4 emissions from small landfills and industrial landfills is simpler. Methane generation in small landfills is estimated by applying an emissions factor of .26 ft^3/ton/day estimated tons of WIP in small landfills. High and low estimates are based on an uncertainty factor of ±20 percent.

Methane generation from industrial landfills is estimated as the sum of 7 percent of emissions from large landfills (±15 percent) and of 7 percent of emissions from small landfills (±20 percent).

The result of these procedures is an estimate of methane generation. Net emissions are estimated by discounting these estimates of methane generation to account for oxidation, flaring and recovery. Oxidation is estimated by assuming an oxidation rate of 10 percent, but flaring and recovery must be estimated independent of the model.

This study assumes that flaring and recovery at Missouri landfills remains constant at the 1990 level until the year 2000. The 1990 level is documented in the *1990 Inventory*. After the year 2000, this study assumes a substantial increase in flaring and recovery due to the impact of new federal and state regulations that require certain landfills to develop landfill gas collection systems.[15] The estimate of flaring and recovery after the year 2000 assumes that the landfills required to establish methane collection systems produce 48 percent of the total landfill methane in Missouri[16] and that the average recovery efficiency of the methane collection systems equals 85 percent.[17]

Table 22 summarizes the resulting trend estimates for net methane emissions from Missouri landfills between 1990 and 1996, and Table 23 summarizes projections through 2015. The range of uncertainty reported in Tables 22 and 23 has two sources: uncertainty about the projected quantity of WIP in Missouri landfills and uncertainty deriving from Equations 1 and 2. The low estimate for each year is based on assuming the low WIP scenario, subtracting 15 percent from the emissions estimates for large landfills and subtracting 20 percent from emissions estimates for small landfills. The high estimate is based on assuming the high WIP scenario, adding 15 percent to the emissions estimates for large landfills and adding 20 percent to emissions estimates for small landfills. The "midrange" estimate is the average of the low and high estimate for the year.

Table 22 - Trend estimates of net methane emissions from Missouri landfills, 1990-96

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1991	1992	1993	1994	1995	1996
Low estimate	3,906	4,113	4,266	4,412	4,549	4,678	4,800
High estimate	7,374	7,660	7,788	7,905	8,008	8,097	8,173
Midrange	5,501	5,748	5,895	6,032	6,158	6,273	6,378

[15] *Federal Register,* Vol. 61, No. 49, p. 9905, March 12, 1996. The Missouri Air Pollution Control Program is publishing regulations for St. Louis and the remainder of the state that affect some landfills not covered by the federal regulation. The regulations are intended to control nonmethane organic compounds (NMOCs) but the systems to collect and dispose of NMOCs are expected to remove methane as well; USEPA, *Greenhouse Gas Emissions from Municipal Waste Management, Draft Working Paper*, March 1997, Chapter 7.

[16] Personal communication, Paul Myers, Missouri Air Pollution Control Program, June 12, 1997.

[17] USEPA, *Greenhouse Gas Emissions from Municipal Waste Management, p. 100.*

Table 23 - Projected net methane emissions from Missouri landfills, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1995	2000	2005	2010	2015
Low estimate	3,906	4,678	3,803	4,131	4,037	3,792
High estimate	7,374	8,097	6,187	6,368	6,130	5,871
Midrange	5,501	6,273	4,930	5,205	5,046	4,788

These projections indicate that methane recovery and flaring will not have much effect on net CH_4 emissions from Missouri landfills prior to the year 2000 but will lead to a major reduction after 2000. Regardless of the accuracy of the specific projections in Table 23, it is likely that net methane emissions will peak in the year 1999, decrease to below 1990 levels in the year 2000, gradually increase again until 2006, and then decrease through 2015. However, as was pointed out at the beginning of the section on landfill methane emissions, this pattern could be affected by landfill operators' response to the federal and state regulations or to opportunities to invest in methane capture. Chart 3, which illustrates the magnitude of the effect of these regulations, assumes that landfill operators will invest in flaring and capture only to the extent required by law.

Chart 3 - Estimates of Missouri landfill methane emissions, 1990-2015

Section 2: Methane emissions from livestock

The *1990 Inventory* identified beef, dairy and swine operations as the leading sources of Missouri methane emissions in 1990. The *Inventory* estimated that methane emissions from Missouri beef and dairy cattle operations, swine operations and other livestock totaled nearly 10 million tons (STCDE) in the 1990 baseline year.

The *Inventory* found that cattle and swine operations accounted for nearly all methane emissions from livestock in Missouri. Therefore, this study estimates trends and projections only for cattle and swine. For other livestock — sheep, goats, horses, mules and poultry — the study assumes that methane emissions remain constant at the level estimated in the *1990 Inventory*.

The *Inventory*, following the *State Workbook*, identified two biological processes through which livestock operations lead to the emission of methane enteric fermentation in livestock digestive systems and anaerobic decomposition of livestock manure. The *Inventory* estimated that in the baseline year 97 percent of methane emissions from livestock digestive systems originated from cattle, with beef cattle accounting for 84 percent of all methane from enteric fermentation and dairy cattle accounting for another 13 percent. Similarly, the *Inventory* estimated that in 1990 swine and dairy operations together accounted for about 97 percent of emissions from manure management systems. Swine operations accounted for 64 percent of all methane emitted from decomposition of manure, and dairy operations accounted for another 33 percent.

This study estimates cattle and swine methane emissions trends through 1996 and emissions projections through 2015 using emissions factors developed in the *1990 Inventory*.

Enteric fermentation occurs during digestion when microbes that reside in animal digestive systems break down feed consumed by the animal. The amount of methane produced by an individual animal depends upon its digestive system and the amount and type of feed it consumes. Ruminants such as cattle have the highest methane emissions among all animal types because a significant amount of methane-producing fermentation occurs in their fore-stomachs. Although sheep and goats are also ruminants, they accounted for less than 1 percent of methane emissions from livestock digestive systems in 1990.

The decomposition of livestock manure produces methane when micro-organisms metabolize organic material in the manure. Under anaerobic conditions, the organic material is decomposed by anaerobic and facultative (living in the presence or absence of oxygen) bacteria. The end products of anaerobic decomposition are methane, carbon dioxide and stabilized organic material. Most of the methane emissions from manure management systems in Missouri come from swine and dairy operations because they rely heavily on anaerobic lagoons to dispose of manure. Anaerobic lagoons generate close to the maximum methane potential of the waste. Other livestock systems, including that of beef cattle, are managed using “dry” systems that promote conditions that limit methane production.

The emissions factors used to estimate cattle emissions through 1996 and swine emissions through 2015 were developed from methodology in the *State Workbook* and are summarized in Table 26 and Table 27. The *State Workbook* methodology for estimating methane emissions from enteric fermentation in cattle requires animal estimates for nine different categories of cattle, and the methodology for estimating emissions from manure management requires animal estimates for six different categories of cattle as well as two categories of swine.

The *1990 Inventory* provides a detailed explanation of the methodology used for the historic and trend estimates. In brief, the *Inventory* methodology for estimating emissions from enteric fermentation is based on regional emissions factors for six different categories of beef cattle and three different categories of dairy cattle. The emissions factors were developed using a model of rumen digestion and methane production for cattle feeding systems in the U.S. According to the *Workbook*, this model has been validated for a wide range of feeding conditions.

Similarly, the *Inventory* methodology for estimating emissions from manure management uses a weighted emissions factor for each livestock category, including three dairy categories and three beef categories. The livestock categories and emissions factors used in this study are identical to those used in the *Inventory*. As the *Inventory* explains in greater detail, the model used to estimate emissions is based on four factors — the typical animal mass for each livestock category, the "volatile solids" produced per year for each category, the "maximum methane producing capacity" of a pound of volatile solids for each category, and the potential of manure management systems to produce methane. The emissions factor for each livestock category is weighted to reflect the mix of management systems used to manage manure for that category.

Table 24 summarizes the emissions trends estimated by applying these methods. The total estimated emissions from livestock operations increased by nearly a million tons between 1990 and 1996, with increases in emissions from swine and beef cattle operations offsetting decreases from dairy cattle operations.

Table 24 - Estimated methane emissions from Missouri livestock operations, 1990-96

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**
Beef cattle operations	5,677	5,634	5,772	5,933	6,288	5,956	6,161
Dairy cattle operations	1,808	1,766	1,701	1,686	1,605	1,552	1,477
Swine operations	2,747	2,623	2,705	2,946	3,321	3,401	3,296
Other livestock operations	170	170	170	170	170	170	170
Total	***10,402***	***10,194***	***10,349***	***10,735***	***11,384***	***11,079***	***11,105***

Projections of methane emissions from swine was based on these models because they required projecting only 1 to 2 categories of swine. However, projections of methane emissions from cattle could not be based on these models because they required projecting animal numbers in multiple categories and because there was insufficient data to make these projections. Rather, beef and dairy emissions were projected on the assumption that emissions would grow at the same rate as the total beef or dairy cattle population. Thus, the projections assume that the relative proportion of the different cattle categories will remain constant after 1996.

In addition, the projections of emissions from manure management assume that Missouri swine and dairy operations will continue to rely on anaerobic lagoons at the level at which they were used in 1990. The *State Workbook* estimates that in 1990 anaerobic lagoons were used for manure management in 80 percent of Missouri swine operations, compared to a U.S. average of 29 percent, and in 60 percent of Missouri dairy operations, compared to a U.S. average of 11 percent.

Table 25 summarizes projections of methane emissions from cattle, swine and other livestock. Total estimated emissions from livestock operations are projected to decrease by about 500,000 tons between 1996 and 2015, with emissions decreases from dairy operations partially offset by increases from swine operations. Emissions from beef operations are projected to remain stable throughout the period, with projected emissions for 2015 nearly identical to estimated emissions in 1995 and only slightly lower than estimates for 1996.

Table 25 - Projected methane emissions from Missouri livestock operations, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1995	2000	2005	2010	2015
Beef cattle	5,677	5,956	5,736	5,971	5,901	5,910
Dairy cattle	1,808	1,552	1,238	1,023	865	731
Swine	2,747	3,401	3,378	3,572	3,766	4,006
Other livestock	170	170	170	170	170	170
Total	***10,402***	***11,079***	***10,522***	***10,736***	***10,702***	***10,817***

Table 26 - Multipliers for methane emissions from enteric fermentation in cattle and swine

		Multiplier (tons / yr)
Dairy cattle		
E1	Replacements 0-12 months age	0.02080
E2	Replacements 12-24 months age	0.06315
E3	Mature cows	0.12035
Beef cattle		
E4	Replacements 0-12 months age	0.02240
E5	Replacements 12-24 months age	0.06690
E6	Mature cows	0.06545
E7	Weanling steer/heifer	0.02485
E8	Yearling steer/heifer	0.05170
E9	Bulls	0.11000
Swine		0.00165

Table 27 - Multipliers for methane emissions from cattle and swine manure

	Weighted Emissions Coefficient (tons per animal)	Weighted Emissions Coefficient (tons per 1,000 animals)
Cattle - mature dairy	0.18732	187.32
Cattle - mature non-dairy		
Female beef cows	0.00304	3.04
Male - Breeding bulls	0.00438	4.38
Cattle - young		
Pre-weaned calves	0.00110	1.10
Growing	0.00219	2.19
Feedlot-fed	0.00492	4.92
Swine		
Market	0.02398	23.98
Breeding	0.12363	123.63

Section 3: Methane emissions from cattle

Table 28 summarizes trend estimates for methane emissions from Missouri cattle operations. Emissions from cattle remained nearly stable between 1990 and 1996, with increases in emissions from beef operations offsetting decreases in emissions from dairy operations. Emissions are projected to decline by about a half million tons through 1990 and then remain nearly stable through 2015, with increases in emissions from beef continuing to offset decreases from dairy.

The primary determinant of emissions from cattle is historic. Projected numbers of beef and dairy cattle in Missouri are summarized in Table 30 for the years 1986 through 2015.[18] As Charts 4 and 5 indicate, the projected growth in Missouri beef cattle numbers is somewhat more optimistic than that for the U.S. in general, whereas the projection for Missouri dairy cattle numbers indicates a steeper drop than for U.S. dairy cattle in general.

Table 28 - Estimated methane emissions from Missouri cattle, 1990-96

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1991	1992	1993	1994	1995	1996
Beef	5,677	5,634	5,772	5,933	6,288	5,956	6,161
Dairy	1,808	1,766	1,701	1,686	1,605	1,552	1,477
Total	***7,485***	***7,401***	***7,474***	***7,619***	***7,893***	***7,508***	***7,638***

Table 29 - Projected methane emissions from Missouri cattle, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1995	2000	2005	2010	2015
Beef	5,677	5,956	5,636	6,074	6,210	6,420
Dairy	1,808	1,552	1,238	1,023	852	700
Total	***7,485***	***7,508***	***6,874***	***7,097***	***7,062***	***7,120***

[18] Historic numbers are taken from the 1990 to 1995 editions of Missouri Department of Agriculture, *Missouri Farm Facts.* Projections are extrapolated from national and state projections prepared by the Food and Agriculture Policy Research Institute (FAPRI).

Table 30 - Historic and projected growth rates of cattle population in Missouri beef and dairy operations, 1986-2015

Units: 1,000 Head

		Beef Growth		*Dairy Growth*	
	Missouri Historic & Projected Data	**National Historic & Projected Data**	**Rate of Change**	**Missouri Historic & Projected Data**	**Rate of Change**
1986	4,450	89,554		236	
1987	4,273	87,346	-2.5%	232	-1.7%
1988	4,074	85,189	-2.5%	230	-0.9%
1989	3,982	82,486	-3.2%	228	-0.9%
1990	3,974	81,631	-1.0%	223	-2.2%
1991	4,025	82,334	0.9%	213	-4.5%
1992	4,125	83,696	1.7%	208	-2.3%
1993	4,240	85,342	2.0%	209	0.5%
1994	4,455	87,316	2.3%	197	-5.7%
1995	4,225	89,127	2.1%	190	-3.6%
1996	4,285	89,967	0.9%	179	-5.8%
1997	4,200	87,891	-2.3%	171	-4.5%
1998	4,230	86,171	-2.0%	163	-4.7%
1999	4,236	84,677	-1.7%	156	-4.3%
2000	4,242	83,756	-1.1%	150	-3.8%
2001	4,248	83,703	-0.1%	144	-4.0%
2002	4,254	84,697	1.2%	138	-4.2%
2003	4,260	85,973	1.5%	133	-3.6%
2004	4,266	86,771	0.9%	128	-3.8%
2005	4,272	87,188	0.5%	124	-3.1%
2006	4,277	86,843	-0.4%	120	-3.2%
2007	4,283	86,086	-0.9%	116	-3.3%
2008	4,289	86,112	0.0%	112	-3.3%
2009	4,295	86,139	0.0%	108	-3.3%
2010	4,301	86,165	0.0%	105	-3.3%
2011	4,307	86,192	0.0%	101	-3.3%
2012	4,313	86,219	0.0%	98	-3.3%
2013	4,318	86,245	0.0%	95	-3.3%
2014	4,324	86,272	0.0%	92	-3.3%
2015	4,330	86,299	0.0%	89	-3.3%

Chart 4 - Historic and projected Missouri beef cattle numbers compared to U.S. beef cattle history and projections, through 2015

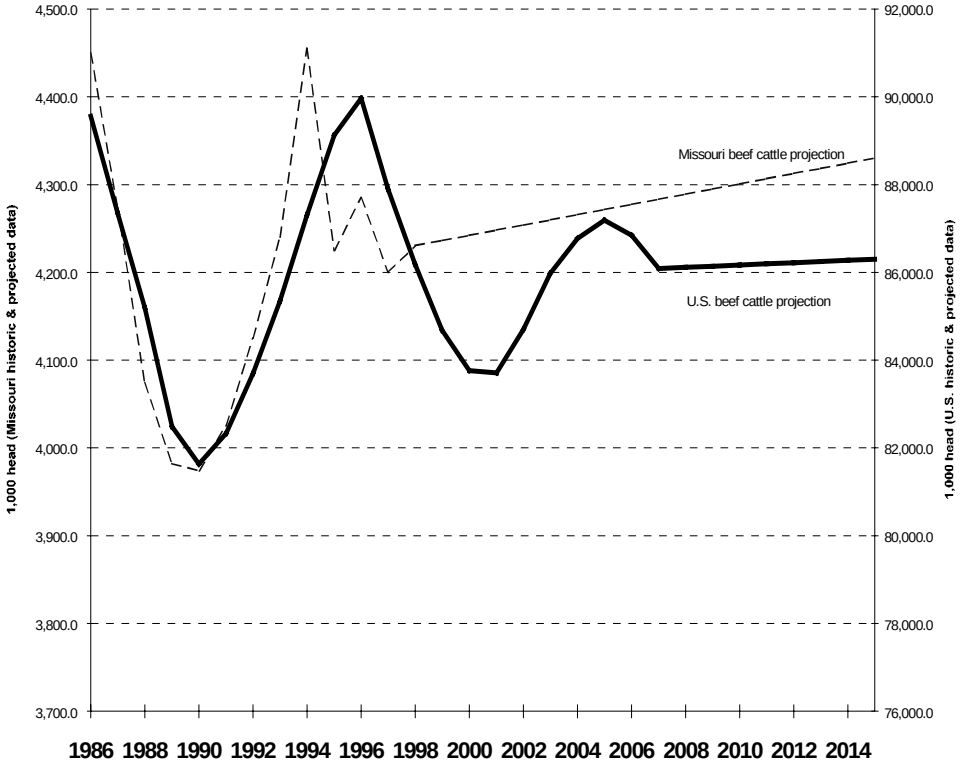
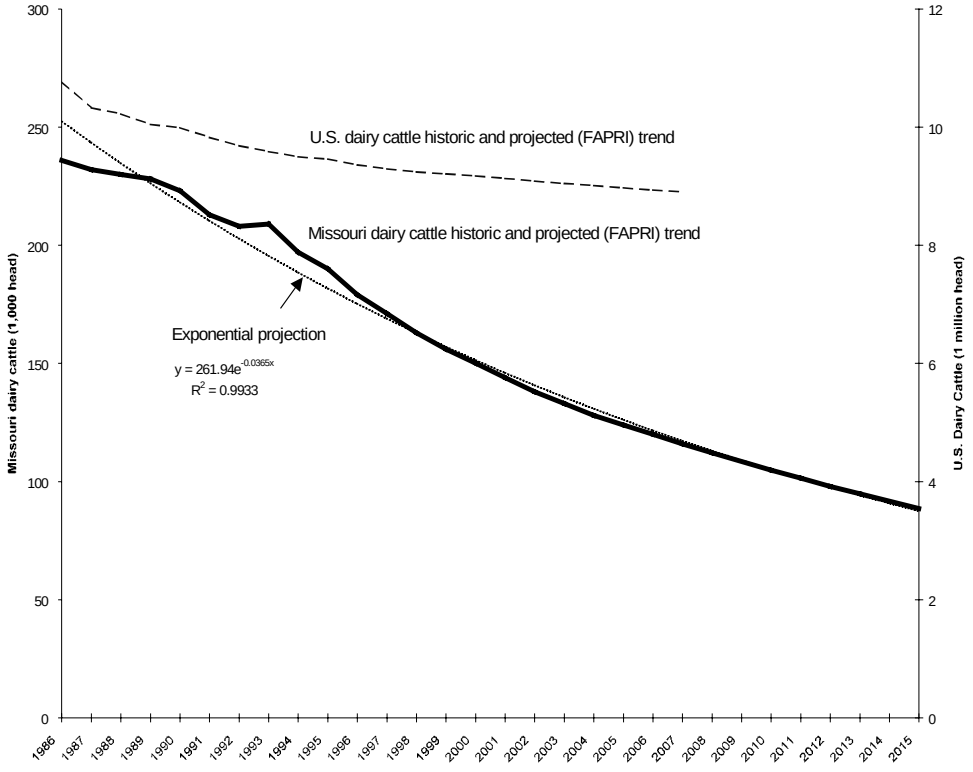


Chart 5 - Historic and projected Missouri dairy cattle numbers compared to U.S. dairy cattle history and projections, through 2015



The following worksheets summarize the steps taken to estimate historic and projected methane emissions from cattle operations in Missouri.

Table 31 - Worksheet for estimating methane emissions from enteric fermentation in Missouri beef and dairy cattle operations, based on animal population estimates, 1990-96

Estimated cattle population (1,000 animals) based on enteric fermentation categories

	E1 Dairy rplcmts 1-year	E2 Dairy rplcmts 2-year	E3 Mature dairy cows	E4 Beef rplcmts 1-year	E5 Beef rplcmts 2-year	E6 Mature beef cows	E7 Weanling steers & heifers	E8 Yearling steers & heifers	E9 Mature bulls	*Total Number of Animals*
1990	51	51	226	150	150	1,964	849	849	110	***4,400***
1991	53	53	220	173	173	1,960	805	805	110	***4,350***
1992	58	58	210	160	160	2,030	833	833	110	***4,450***
1993	50	50	210	175	175	2,060	855	855	120	***4,550***
1994	48	48	200	190	190	2,230	860	860	125	***4,750***
1995	40	40	195	183	183	2,105	818	818	120	***4,500***
1996	40	40	185	173	173	2,165	875	875	125	***4,650***

Estimated methane emissions from enteric fermentation in cattle

	E1 Emissions (Tons CH_4)	E2 Emissions (Tons CH_4)	E3 Emissions (Tons CH_4)	E4 Emissions (Tons CH_4)	E5 Emissions (Tons CH_4)	E6 Emissions (Tons CH_4)	E7 Emissions (Tons CH_4)	E8 Emissions (Tons CH_4)	E9 Emissions (Tons CH_4)	Enteric ferment'n (Tons CH_4)
1990	1,061	3,221	27,199	3,360	10,035	128,544	21,098	43,893	12,100	250,510
1991	1,092	3,315	26,477	3,864	11,540	128,282	20,004	41,619	12,100	248,293
1992	1,196	3,631	25,274	3,584	10,704	132,864	20,688	43,040	12,100	253,080
1993	1,040	3,158	25,274	3,920	11,708	134,827	21,247	44,204	13,200	258,576
1994	988	3,000	24,070	4,256	12,711	145,954	21,371	44,462	13,750	270,561
1995	832	2,526	23,468	4,088	12,209	137,772	20,315	42,265	13,200	256,675
1996	832	2,526	22,265	3,864	11,540	141,699	21,744	45,238	13,750	263,458

Table 32 - Worksheet for estimating methane emissions from manure management in Missouri beef and dairy cattle operations, based on animal population estimates, 1990-96

Estimated cattle population (1,000 animals) based on manure management categories

	M1 Mature dairy cows	M2 Mature beef cows	M3 Mature bulls	M4 Pre-weaned calves	M5 Feedlot steers & heifers	M6 Growing steers & heifers	*Total Number of Animals*
1990	226	1,964	110	1,014	87	999	***4,400***
1991	220	1,960	110	990	86	984	***4,350***
1992	210	2,030	110	1,085	81	934	***4,450***
1993	210	2,060	120	1,080	86	994	***4,550***
1994	200	2,230	125	975	98	1,122	***4,750***
1995	195	2,105	120	960	90	1,030	***4,500***
1996	185	2,165	125	1,030	92	1,053	***4,650***

Estimated methane emissions from manure management in cattle

	M1 Emissions (Tons CH_4)	M2 Emissions (Tons CH_4)	M3 Emissions (Tons CH_4)	M4 Emissions (Tons CH_4)	M5 Emissions (Tons CH_4)	M6 Emissions (Tons CH_4)	Manure mgmt. (Tons CH_4)
1990	42,335	5,980	482	1,112	191	4,913	55,013
1991	41,211	5,968	482	1,086	188	4,840	53,775
1992	39,338	6,181	482	1,190	178	4,591	51,961
1993	39,338	6,272	526	1,185	190	4,885	52,396
1994	37,465	6,790	548	1,069	214	5,519	51,605
1995	36,528	6,409	526	1,053	197	5,066	49,780
1996	34,655	6,592	548	1,130	201	5,179	48,305

Table 33 - Estimated methane emissions and carbon dioxide equivalent (STCDE) from enteric fermentation and manure management in Missouri beef and dairy cattle operations, 1990-2015

	CH_4 from enteric ferment'n in beef cattle (Tons)	CH_4 from enteric ferment'n in dairy cattle (Tons)	CH_4 from manure mgmt. in beef cattle (Tons)	CH_4 from manure mgmt. in dairy cattle (Tons)	Total CO_2 from beef cattle (STCDE)	Total CO_2 from dairy cattle (STCDE)	CO_2 from enteric ferment'n in all cattle (STCDE)	CO_2 from manure mgmt. in all cattle (STCDE)	*Total CO_2 from all cattle operations (STCDE)*
1990	219,030	31,481	12,678	42,335	5,676,836	1,808,483	6,137,502	1,347,817	***7,485,320***
1991	217,409	30,884	12,564	41,211	5,634,343	1,766,340	6,083,188	1,317,495	***7,400,683***
1992	222,979	30,101	12,623	39,338	5,772,260	1,701,244	6,200,460	1,273,044	***7,473,504***
1993	229,105	29,471	13,058	39,338	5,932,993	1,685,818	6,335,106	1,283,705	***7,618,811***
1994	242,504	28,058	14,140	37,465	6,287,777	1,605,297	6,628,748	1,264,326	***7,893,073***
1995	229,849	26,826	13,252	36,528	5,955,967	1,552,181	6,288,547	1,219,601	***7,508,148***
1996	237,835	25,623	13,650	34,655	6,161,387	1,476,801	6,454,709	1,183,479	***7,638,188***
1997	232,347	24,478	13,336	33,106	6,019,233	1,410,798	6,292,214	1,137,817	***7,430,031***
1998	227,799	23,332	13,074	31,557	5,901,393	1,344,796	6,152,715	1,093,475	***7,246,190***
1999	223,850	22,330	12,848	30,202	5,799,100	1,287,044	6,031,424	1,054,720	***7,086,144***
2000	221,415	21,472	12,708	29,040	5,736,014	1,237,543	5,950,721	1,022,836	***6,973,557***
2001	221,276	20,613	12,700	27,879	5,732,426	1,188,041	5,926,286	994,181	***6,920,467***
2002	223,903	19,754	12,851	26,717	5,800,470	1,138,539	5,969,594	969,415	***6,939,009***
2003	227,277	19,038	13,045	25,749	5,887,889	1,097,288	6,034,733	950,444	***6,985,177***
2004	229,385	18,322	13,165	24,781	5,942,494	1,056,036	6,068,838	929,692	***6,998,530***
2005	230,488	17,750	13,229	24,007	5,971,068	1,023,035	6,081,834	912,270	***6,994,103***
2006	229,577	17,177	13,176	23,232	5,947,452	990,034	6,045,471	892,015	***6,937,486***
2007	227,574	16,605	13,062	22,458	5,895,570	957,033	5,982,377	870,225	***6,852,603***
2008	227,644	16,055	13,066	21,714	5,897,394	925,325	5,970,624	852,095	***6,822,719***
2009	227,715	15,523	13,070	20,994	5,899,218	894,667	5,959,317	834,568	***6,793,885***
2010	227,785	15,008	13,074	20,299	5,901,042	865,025	5,948,442	817,625	***6,766,067***
2011	227,856	14,511	13,078	19,626	5,902,866	836,366	5,937,984	801,247	***6,739,231***
2012	227,926	14,030	13,082	18,976	5,904,690	808,655	5,927,930	785,415	***6,713,345***
2013	227,996	13,565	13,086	18,347	5,906,514	781,863	5,918,266	770,111	***6,688,377***
2014	228,067	13,116	13,090	17,739	5,908,338	755,959	5,908,980	755,317	***6,664,296***
2015	228,137	12,681	13,094	17,152	5,910,162	730,913	5,900,058	741,016	***6,641,074***

Section 4: Methane emissions from swine

Missouri total swine population was divided into market and breeding swine to accommodate the methodology for estimating methane emissions from manure. Missouri swine population through 2006, total and by category, was projected assuming that the growth rate of Missouri swine would be equal to the growth rates projected by FAPRI for U.S. market and breeding swine. To project Missouri swine population through 2015, growth rates for 2007 to 2015 were projected from the FAPRI growth rates for 1996 to 2006 using least squares linear regression. The resulting projections, illustrated in Chart 6 and summarized in Table 35, indicate that by 2015 Missouri's swine population will approach 4.5 million head, the previous historic high achieved in 1979.

Chart 6 - Estimated historic and projected Missouri swine population, 1975-2015

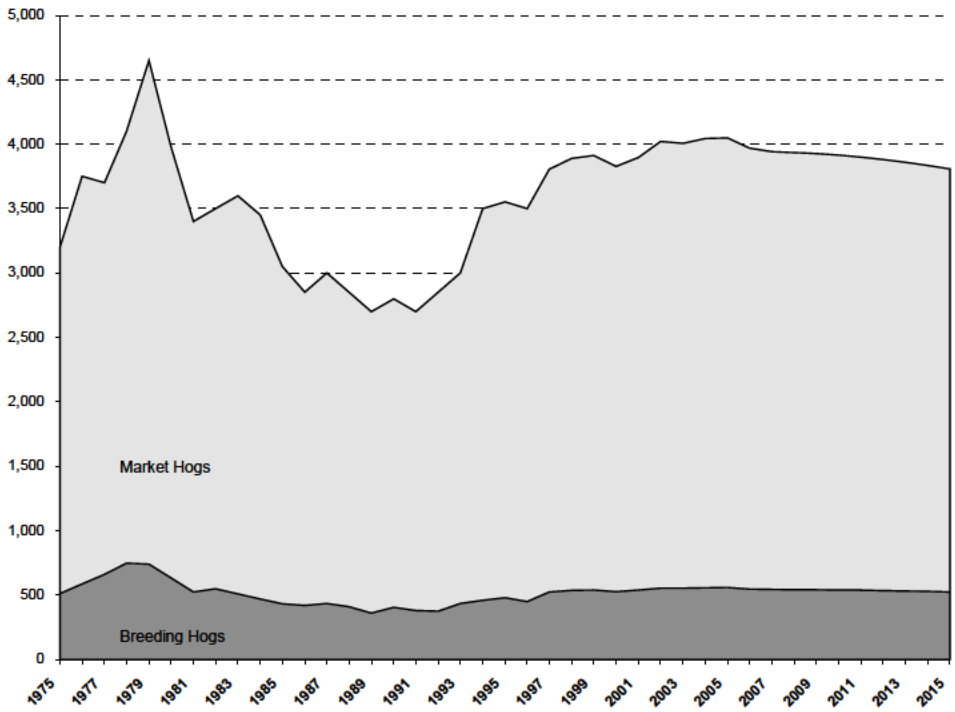


Table 34 - Estimated methane emissions from Missouri swine operations, 1990-96

	Enteric ferment'n (tons CH_4)	*Manure-breeding (tons CH_4)*	*Manure-other (tons CH_4)*	*Manure-total (tons CH_4)*	*Combined Emissions (tons CH_4)*	*Enteric ferment'n (equiv. tons CO_2)*	*Manure mgmt. (equiv. tons CO_2)*
1990	4,620	50,070	57,433	107,503	112,123.2	113,190	2,633,828
1991	4,455	46,980	55,634	102,614	107,068.9	109,148	2,514,040
1992	4,703	46,361	59,351	105,713	110,415.2	115,211	2,589,961
1993	4,950	53,779	61,509	115,289	120,238.7	121,275	2,824,574
1994	5,775	56,870	72,900	129,770	135,545.2	141,488	3,179,369
1995	5,858	59,343	73,620	132,962	138,819.7	143,509	3,257,573
1996	5,775	55,634	73,140	128,774	134,548.7	141,488	3,154,955
1997	6,277	64,869	78,640	143,509	149,785.8	153,779	3,515,973
1998	6,419	66,340	80,424	146,765	153,183.6	157,268	3,595,731
1999	6,455	66,708	80,870	147,578	154,033.1	158,140	3,615,670
2000	6,312	65,237	79,086	144,323	150,635.3	154,652	3,535,913
2001	6,431	66,463	80,573	147,036	153,466.8	157,559	3,602,377
2002	6,633	68,548	83,100	151,648	158,280.3	162,500	3,715,367
2003	6,609	68,302	82,803	151,105	157,714.0	161,919	3,702,074
2004	6,668	68,915	83,546	152,461	159,129.7	163,373	3,735,306
2005	6,680	69,038	83,695	152,733	159,412.9	163,663	3,741,953
2006	6,550	67,689	82,059	149,749	156,298.3	160,466	3,668,842
2007	6,502	67,199	81,465	148,664	155,165.7	159,303	3,642,256
2008	6,493	67,100	81,346	148,446	154,938.8	159,070	3,636,930
2009	6,478	66,947	81,160	148,107	154,585.1	158,707	3,628,628
2010	6,458	66,740	80,908	147,648	154,105.4	158,214	3,617,368
2011	6,432	66,478	80,591	147,068	153,500.8	157,594	3,603,176
2012	6,402	66,162	80,208	146,371	152,772.6	156,846	3,586,084
2013	6,366	65,794	79,762	145,556	151,922.6	155,973	3,566,131
2014	6,326	65,374	79,253	144,627	150,952.7	154,977	3,543,363
2015	6,280	64,903	78,682	143,585	149,865.1	153,861	3,517,834

Table 35 - Estimated and projected Missouri swine population, 1975-2015

Units: Number of Animals

	Total Swine	Breeding Swine	Other Swine
1975	3,200	512	2,688
1976	3,750	585	3,165
1977	3,700	660	3,040
1978	4,100	746	3,354
1979	4,650	739	3,911
1980	3,980	633	3,347
1981	3,400	525	2,875
1982	3,500	550	2,950
1983	3,600	510	3,090
1984	3,450	470	2,980
1985	3,050	430	2,620
1986	2,850	420	2,430
1987	3,000	435	2,565
1988	2,850	410	2,440
1989	2,700	360	2,340
1990	2,800	405	2,395
1991	2,700	380	2,320
1992	2,850	375	2,475
1993	3,000	435	2,565
1994	3,500	460	3,040
1995	3,550	480	3,070
1996	3,500	450	3,050
1997	3,804	525	3,279
1998	3,890	537	3,354
1999	3,912	540	3,372
2000	3,826	528	3,298
2001	3,898	538	3,360
2002	4,020	554	3,465
2003	4,005	552	3,453
2004	4,041	557	3,484
2005	4,049	558	3,490
2006	3,969	548	3,422
2007	3,941	544	3,397
2008	3,935	543	3,392
2009	3,926	542	3,384
2010	3,914	540	3,374
2011	3,898	538	3,361
2012	3,880	535	3,345
2013	3,858	532	3,326
2014	3,834	529	3,305
2015	3,806	525	3,281

Estimates of methane emission trends from swine operations, calculated by applying emissions factors summarized in Tables 36 and 37, are as follows:

Table 36 - Estimated methane emissions from Missouri swine, 1990-96

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

1990	1991	1992	1993	1994	1995	1996
2,747	2,623	2,705	2,946	3,321	3,401	3,296

Table 37 - Projected methane emissions from Missouri swine, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

1990	1995	2000	2005	2010	2015
2,747	3,401	3,691	3,906	3,776	3,672
Average annual growth rate since 1990		***3.0%***	***2.4%***	***1.6%***	***1.2%***

Section 5: Methane emissions from other agricultural sources

In addition to livestock operations, the *1990 Inventory* identified rice cultivation and the burning of crop wastes as agricultural sources of methane emissions in Missouri. In 1990, rice cultivation contributed less than 1 percent of methane emissions from agriculture, and methane emissions from combustion of crop wastes was equivalent to less than 2 tons of carbon dioxide. Because these emissions constitute a very small fraction of all anthropogenic methane emissions in Missouri, this study assumes that emissions from these sources have remained constant since 1990.

Rice cultivation in southeast Missouri increased between 1990 and 1995, reaching a high of about 120,000 acres in 1995 compared to about 83,000 acres average in 1990. However, in 1996 the acreage decreased to about 90,000 acres, close to the 1990 level, in response to changes in subsidy requirements introduced by the 1995 farm bill. Future rice acreage is likely to remain fairly stable and is unlikely to exceed 120,000 acres.[19]

As the *1990 Inventory* points out, a number of factors besides planted acreage affect methane emissions from rice cultivation. The *Inventory* discusses several factors — such as the fact that Missouri rice fields are located farther north than the fields that served as the basis for developing the estimation methodology, and the relatively low use of organic fertilizer in Missouri rice fields — which suggest that actual methane emissions are at the lower end of the range estimated for the *1990 Inventory*. For these reasons, no attempt was made to estimate an increase in emissions due to the increase in Missouri's planted rice acreage.

[19]Personal communication, Bruce Beck, University of Missouri Extension Service, Poplar Bluff, September 17, 1997.

Part 3: Nitrous oxide emissions — trends and projections

The *1990 Inventory* estimated nitrous oxide (N_2O) emissions from several economic activities: use of nitrogenous fertilizers, burning of crop wastes, highway transportation and nitric acid production in Missouri. As discussed in the *1990 Inventory*, the processes leading to N_2O emissions are affected by multiple factors in addition to the level of the associated economic activity. Thus, estimates of nitrous oxide (N_2O) emissions are subject to higher uncertainty than estimates of methane emissions and much higher uncertainty than estimates of CO_2 emissions.

Because (1) N_2O emissions are a minor portion of Missouri greenhouse gas emissions, (2) estimates of N_2O are subject to a high degree of uncertainty and (3) resources for the analysis were limited, it was prudent to concentrate the analysis of N_2O emissions on the leading source, agricultural use of nitrogenous fertilizers. This source accounted for more than 60 percent of estimated 1990 N_2O emissions.

Tables 38 and 39 summarize trends and projections estimates for nitrous oxide emissions in Missouri. The estimates for N_2O emissions from fertilizer use are midpoint estimates. The estimates for other sources are assumed to remain constant at 1990 levels.

Table 38 - Estimated nitrous oxide emissions in Missouri, 1990-96

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1991	1992	1993	1994	1995	1996
Total nitrous oxide emissions	3,805	3,859	3,925	4,001	3,877	3,855	3,820
Agriculture	2,333	2,388	2,454	2,530	2,406	2,383	2,348
Use of nitrogenous fertilizers	2,333	2,388	2,454	2,530	2,406	2,383	2,348
Disposal of crop wastes by burning	0	0	0	0	0	0	0
Highway transportation	1,080	1,080	1,080	1,080	1,080	1,080	1,080
Nitric acid production	391	391	391	391	391	391	391

Table 39 - Projected nitrous oxide emissions in Missouri, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1996	2000	2005	2010	2015
Total nitrous oxide emissions	3,805	3,820	3,875	3,872	3,870	3,868
Agriculture	2,333	2,348	2,403	2,401	2,399	2,397
Use of nitrogenous fertilizers	2,333	2,348	2,403	2,401	2,399	2,397
Disposal of crop wastes by burning	0	0	0	0	0	0
Highway transportation	1,080	1,080	1,080	1,080	1,080	1,080
Nitric acid production	391	391	391	391	391	391

Section 1: Nitrous oxide emissions from nitrogenous fertilizers

The *1990 Inventory* estimated that about 60 percent of Missouri's 1990 anthropogenic nitrous oxide (N_2O) emissions were due to the use of nitrogenous fertilizers. In 1990, between 700 and 14,000 tons of N_2O were released due to use of nitrogenous fertilizers, with a midpoint estimate of about 7,000 tons. The carbon dioxide equivalent of these emissions was between 219,000 and 4.5 million tons of CO_2, with a midpoint of about 2.3 million tons.

The wide range reflects the multiplicity of factors in addition to type and quantity of fertilizer that can affect N_2O emissions from this source. Nitrous oxide (N_2O) is produced from soil nitrogen through the microbial processes of denitrification and nitrification.[20] All other things being equal, an increase in the use of nitrogenous fertilizers leads to an increase in nitrogen in the soil and ultimately to an increase in the amount of N_2O emitted. However, as the *1990 Inventory* discusses, multiple factors affect the level of emissions. There is scientific consensus that numerous factors influence the biological processes of the soil micro-organisms that produce nitrous oxide emissions, but research has not been able to definitively establish the complex interaction of these factors.

Management factors that may affect emissions include the application technique, crop type, timing of application, tillage practices, use of other chemicals, irrigation and residual Nitrogen from crops or fertilizers. Current research suggests that high application rates for fertilizer, shallow placement of fertilizer, application in fall rather than spring, and no-till methods as opposed to tillage all may increase N_2O emissions.

Factors beyond managerial control that may affect emissions include temperature, precipitation, soil moisture content, availability of oxygen, porosity, pH, organic carbon content, thaw cycle, micro-organisms present and soil type. Experiments have shown that increases in pH, soil temperature, soil moisture, organic carbon content and oxygen supply may increase N_2O emissions.

Adopting the methodology of the *1990 Inventory*, this study estimates that N_2O emissions from use of nitrogenous fertilizers in Missouri increased by about 200,000 tons (midpoint STCDE) between 1990 and 1993, then decreased to about the 1990 emissions level between 1993 and 1996. These estimates are based on methodology from the *1990 Inventory.* The methodology estimates low, midpoint and high N_2O emissions by applying low, midpoint and high emissions coefficients to a three-year average of nitrogen fertilizer application.

Table 40 summarizes the data used to estimate emissions during 1990 and 1996. Data on annual application was derived from semi-annual reports of the Fertilizer Control Services (FCS) office of the Agricultural Experiment Station, University of Missouri-Columbia, on the shipment of fertilizers for use in Missouri. It is assumed that shipment for use provides a good estimate of actual fertilizer consumption.

[20] Denitrification is the process by which nitrates or nitrites are reduced by bacteria and which results in the escape of nitrogen into the air. Nitrification is the process by which bacteria and other micro-organisms oxidize ammonium salts to nitrites, and further oxidize nitrites to nitrates.

Table 40 - Worksheet for estimates of N_2O emissions from nitrogenous fertilizer use in Missouri, 1990-96

	Tons	*Tons*	*Tons*			*Tons*		
	Annual	3-yr. ave.	Nitrogen Emitted			Nitrous Oxide Emissions		
	N Applied	N Applied	Low (C=.0011)	Midpoint (C=.0117)	High (C=.0224)	Low	Midpoint	High
1989	418,524							
1990	378,953	396,608	436	4,640	8,884	686	7,292	13,961
1991	392,348	405,861	446	4,749	9,091	702	7,462	14,286
1992	446,281	417,098	459	4,880	9,343	721	7,669	14,682
1993	412,665	430,024	473	5,031	9,633	743	7,906	15,137
1994	431,126	408,929	450	4,784	9,160	707	7,518	14,394
1995	382,996	405,098	446	4,740	9,074	700	7,448	14,259
1996	401,172	399,161	439	4,670	8,941	690	7,339	14,050

Table 41 summarizes the resulting trend estimates. These estimates were derived by applying the Global Warming Factor (GWF) of 320 STCDE per ton of N_2O to the N_2O emissions estimates in the final three columns of Table 40. Summaries of greenhouse gas emissions appearing in other sections of this report use only the midpoint estimates.

Table 41 - Trend estimates for N_2O emissions from use of nitrogenous fertilizer in Missouri, 1990-96

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**
Low	219	224	231	238	226	224	221
Midpoint	2,333	2,388	2,454	2,530	2,406	2,383	2,348
High	4,467	4,572	4,698	4,844	4,606	4,563	4,496

N_2O emissions between 1990 and 2015 were projected by applying least-squares linear regression to the 1990 to 1996 emissions estimates. Based on this analysis, midpoint N_2O emissions between 1990 and 2015 will remain constant at about 2.4 million tons (midpoint STCDE), equivalent to a 0.1 percent growth rate in emissions between 1990 and 2015. Table 42 summarizes the resulting projections.

Table 42 - Estimated projections of N_2O emissions from use of nitrogenous fertilizer in Missouri, 1990-2015

Units: 1,000 Short Tons Carbon Dioxide Equivalent (STCDE)

	1990	1996	2000	2005	2010	2015
Low	219	221	226	226	226	225
Midpoint	2,333	2,348	2,403	2,401	2,399	2,397
High	4,467	4,496	4,601	4,597	4,593	4,589

Part 4: Perfluorinated carbon (PFC) emissions — trends and projections

Aluminum manufacture is the sole source of PFC emissions in Missouri. Two PFCs — tetrafluoromethane (CF_4) and hexafluoroethane (C_2F_6) — are emitted during the electrolytic reduction of alumina in the primary smelting process.[21] Although CF_4 and C_2F_6 are inert and therefore pose no health or local environmental problems, they are very potent greenhouse gases. To estimate the carbon dioxide equivalent of emissions of CF_4 and C_2F_6, this study uses the 1995 IPPC Global Warming Potential (GWP) factors. The GWP factor for CF_4 equals 6,300 STCDE per ton of PFC, and the GWP factor for C_2F_6 equals 12,500 STCDE per ton of PFC.

Noranda Aluminum, Missouri's only aluminum manufacturer, has joined in the Voluntary Aluminum Industry Partnership (VAIP) program sponsored by USEPA. Noranda provided this project with estimates of PFC emissions for 1990 to 1996 and projections for 2005 and 2015.[22]

PFCs are formed during disruptions of the production process known as anode effects, which are characterized by a sharp rise in voltage across the production vessel. The magnitude of emissions for a given level of production depends on the frequency and duration of the anode effects during that production period. The more frequent and long-lasting the anode effects, the greater the emissions. The estimates in Table 43 reflect Noranda's successful effort to reduce anode effects in its production process.

Table 43 - Noranda Aluminum estimates of PFC emissions in Missouri, 1990-2015

	Aluminum production (Metric tons)	CF_4 emissions (Metric tons)	C_2F_6 emissions (Metric tons)	CF_4 emissions (Short tons)	C_2F_6 emissions (Short tons)	CF_4 emissions (STCDE)	C_2F_6 emissions (STCDE)
1990	214,969	554	55	611	61	3,847	763
1991	216,140	172	17	190	19	1,194	237
1992	218,871	131	13	144	14	910	181
1993	219,640	139	14	153	15	965	192
1994	200,132	126	13	139	14	875	174
1995	217,773	128	13	141	14	889	176
1996	220,439	77	8	85	8	535	106
2005	250,000	55	6	61	6	382	76
2015	250,000	50	5	55	6	347	69

[21]Perfluorinated carbons are not emitted during the smelting of recycled aluminum.

[22]Communication from Dave Hart, Noranda Aluminum, April 16, 1997.

Greenhouse Gas Emission Trends and Projections for Missouri, 1990-2015 Technical Report

Chapter 6

CO_2 Sequestration Due to Forest Growth

Chapter 6: CO_2 sequestration due to forest growth

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Part 1: Sequestration of CO_2 due to forest growth — trends and projections

Nearly a third of Missouri's total land area is forested. Missouri's 14 million acres of forests are primarily a mixture of various hardwood species, mainly oak and hickory. Over the past several decades, forestry management practices in the state have permitted continued biomass growth in these forested acres.

When forest biomass increases, CO_2 is taken up in woody biomass. Section 1 of this chapter discusses trends and projections in CO_2 uptake by Missouri's forests. The *1990 Inventory* estimates that in the 1990 baseline year biomass growth in Missouri forests took up between 31.4 and 37.9 million tons of CO_2, with a midpoint estimate of 27.1 million tons. A range is estimated due to uncertainty in estimating the uptake that occurs due to the growth of tree roots.

Although the U.S. Forest Service, North Central Forest Experiment Station (NCFES) periodically estimates above-ground biomass in Missouri forests, it does not estimate below-ground biomass. Therefore, estimates of root biomass are based on studies of the ratio of root biomass to above-ground biomass for the species that dominate Missouri forests. These studies have provided a range of results. The low sequestration estimate assumes that biomass in tree roots equals about 18 percent of trees' above-ground biomass; the high estimate assumes that root biomass equals about 43 percent of above-ground biomass.

Uptake must be distinguished from *net sequestration*, which is affected by the impact of forest removals. Forest removals include fire wood, commercial round wood and residue removed from the forest.

Section 2 estimates the impact of forest removals following a simple methodology prescribed in *the State Workbook*.[1] In this simple approach, net sequestration is presumed to equal uptake minus removals. All the estimates of net sequestration in this chapter are based on this methodology. For example, in 1990, the estimated impact of Missouri's forest removals was to offset about 7.5 million tons of forest uptake, resulting in a midpoint net sequestration estimate of about 27 million tons of CO_2.

Section 3 discusses an alternative approach to estimating the impact of forest removals which acknowledges the role of forest products in sequestering carbon. This approach is theoretically more sound but also more complicated. Use of the simpler methodology is a likely source of error in the estimates presented in this chapter, but as Section 3 points out, this source of error must be assessed in the context of other sources of error in the analysis.

Forest biomass growth has been taking place for decades in Missouri's forests and is expected to continue. Table 1 summarizes estimated 1990 through 1996 sequestration trends.

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[1] USEPA, State and Local Climate Change Outreach Program, *State Workbook: Methodologies for Estimating Greenhouse Gas Emissions*, 1995 and 1998 (draft), Washington D.C. Hereafter referred to as the *State Workbook*.

Table 1 - Midpoint estimates of net CO_2 sequestration due to growth of biomass in Missouri forests, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1991	1992	1993	1994	1995	1996
Potential sequestration	34,615.00	34,615.00	34,615.00	34,615.00	34,615.00	34,615.00	34,615.00
Removals	7,541.00	7,654.48	7,953.62	8,255.90	8,558.79	8,726.38	8,882.91
Net sequestration	27,074.00	26,960.52	26,661.38	26,359.10	26,056.21	25,888.62	25,732.09

In order to accommodate uncertainty about future forest management in Missouri, the NCFES has developed two scenarios projecting forest removals in Missouri through 2019, a low-removals scenario and a high-removals scenario.[2] These scenarios are integrated into Table 2, which summarizes projections of net sequestration through 2015. The midpoint estimate for removals in Table 2 is based on a numeric average of the NCFES scenarios for the level of forest removals. This study relies on the midpoint estimate for removals when summarizing overall greenhouse gas sinks and sources.[3] Like Table 1, Table 2 uses a midpoint estimate for the ratio of roots to above-ground biomass.

Table 2 - Projected CO_2 sequestration due to growth of biomass in Missouri forests, by level of biomass removals, 1990-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

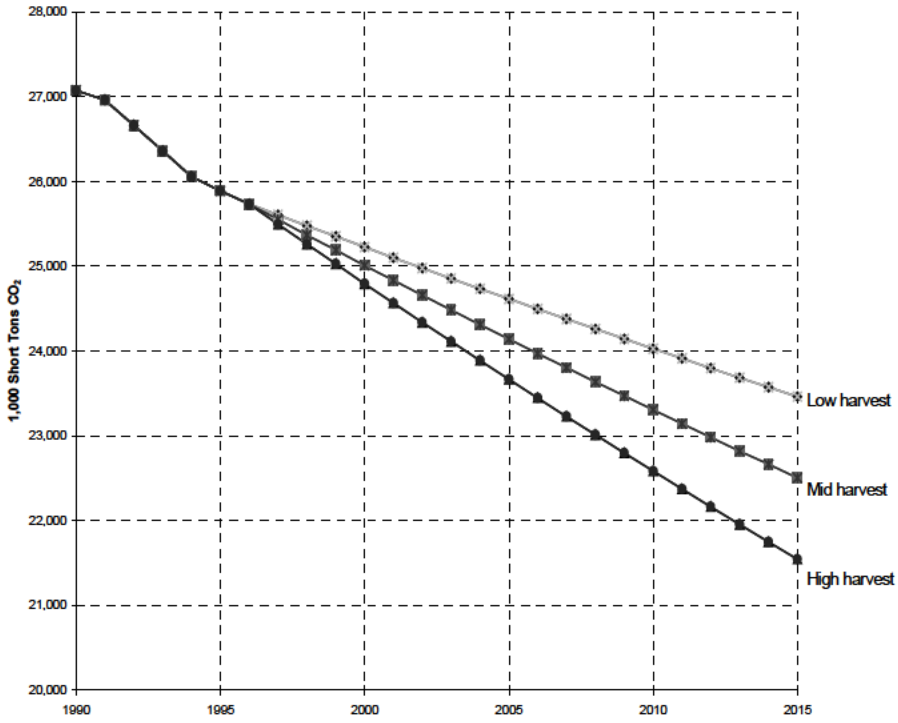
	1990	1995	2000	2005	2010	2015
Potential sequestration	34,615	34,615	34,615	34,615	34,615	34,615
Removals						
Low case	7,541	8,726	9,390	10,001	10,588	11,153
Mid point	7,541	8,726	9,606	10,475	11,310	12,112
High case	7,541	8,726	9,822	10,949	12,032	13,071
Net sequestration						
Low case	27,074	25,889	25,225	24,614	24,027	23,462
Mid point	27,074	25,889	25,009	24,140	23,305	22,503
High case	27,074	25,889	24,793	23,666	22,583	21,544

[2] USDA/NCFES, *Missouri's Forest Resource, 1989: an Analysis*, pp. 21-22.

[3] The rationale for using the midpoint estimate for removals is that it is the single best summary of USFS/NCFES scenarios for low and high growth of removals. However, a case can be made for using the high removals scenario. Dennis May of NCFES has indicated that growth in removals during 1994 through 1996 appears to fit the high growth scenario and that the geographic scope of the market for Missouri pulpwood appears to have grown to include southern Arkansas pulp mills. (Personal communication, 10/15/97). The growth of a "chip mill" industry in Missouri would also put upward pressure on the removal rate.

Chart 1 illustrates the impact of removals, according to the different scenarios, on net sequestration due to forest growth.

Chart 1 - Historic and projected net CO_2 sequestration under the low-, mid- and high-removals scenarios



The following sections discuss the two variables — rate of biomass growth and rate of forest removals — that primarily determine the net sequestration estimate.

Section 1: Forest biomass growth

The trend and projection analyses assume that through 2015, the acreage, species composition and biomass growth rate of Missouri forests will remain constant at 1990 levels.[4] The assumed growth rate for Missouri forest biomass, 3 percent per annum, is taken from a Missouri statewide forest inventory completed in 1989 by the U.S. Forest Service, North Central Forest Experiment Station (NCFES) with assistance from the Missouri Department of Conservation (MDC).

A decrease in biomass growth rate would decrease annual sequestration of CO_2, whereas an increase in the growth rate would increase sequestration. Table 3 summarizes an analysis of the sensitivity of sequestration to the growth rate. A ±1 percent change in the growth rate would change the midpoint estimate for sequestration by about ±33 percent.

Table 3 - Sensitivity of estimates of CO_2 uptake to forest biomass growth rate

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

2.00%	**low**	(20,911)
	high	(25,243)
2.50%	**low**	(26,139)
	high	(31,553)
3.00%	**low**	(31,367)
	high	(37,864)
3.50%	**low**	(36,594)
	high	(44,175)
4.00%	**low**	(41,822)
	high	(50,485)

[4] The *1990 Inventory* found modest increases in total forested acreage. However, some observers of the "chip mill" industry which has recently moved into Missouri have argued that if landowners selling to chip mills fail to follow sustainable harvesting practices, the result could be a reduction in forested acreage. (St. Louis Post Dispatch, "Paper Companies Turn to Missouri," September 21, p. A1.)

In theory, forest maturation could result in a decrease in the biomass growth rate.[5] However, the probability of a shift in growth rate in either direction is not known. Data to assess 1990 to 1996 forest biomass growth trends will not be available until completion of the next statewide inventory, scheduled to be completed in 1999.[6]

[5] Personal communication, Wiley Barbour, USEPA, September 12, 1997.

[6] Personal communication, Mark Hansen, NCFES, April 24, 1997.

Section 2: Forest removals

This section analyzes the impact of forest removals using methodology prescribed in the USEPA's *State Workbook*. This methodology accounts for forest removals by assuming that any increase in forest removals results in a decrease in CO_2 sequestration that would result from forest growth. This methodology, drawn from the *State Workbook*, is acknowledged as valid by the Intergovernmental Panel on Climate Change (IPCC), which serves as the international forum for developing guidelines on methodology for greenhouse gas inventories. However, IPCC also acknowledges an alternative methodology which attempts to account for a variable rate of decay of the carbon in harvested wood depending on its disposition, that is, whether it remains sequestered in a wood product or resides in a landfill where it will be released over time. This alternative methodology, which is discussed in Section 3 of this chapter, is theoretically superior to the methodology prescribed by the *State Workbook* and presented in Section 2. However, as Section 3 explains, use of this more complicated methodology is impractical for this study.

Forest removals include fuelwood, commercial round wood and residue from commercial timber harvests. These quantities are initially estimated in tons of dry matter, which is then multiplied by conversion factors (.498 tons carbon per ton of dry matter, 3.67 tons CO_2 per ton of carbon) to estimate how much CO_2 sequestration is offset by the removals.

Firewood removals are difficult to estimate because more than 99 percent of all firewood is cut by households, and therefore there are no market transactions that can be traced. According to the most recent estimate available, 924,000 cords of fuelwood were removed from Missouri forests in 1987.[7] Assuming 79 cubic feet of dry matter per cord, this was equivalent to about 73 million cubic feet of dry matter. The analysis assumes that fuelwood removals in 1990 were identical to those in 1987 and that fuelwood removals from 1990 to 1996 grew at the same rate as Missouri's population, totaling about 76.3 million cubic feet in 1996.

Commercial roundwood harvest and residue trends for 1991 and 1994 were drawn from Missouri forest inventories completed by NCFES.[8] According to the inventories, 121.4 million cubic feet were harvested in Missouri in 1991, with 67.6 million cubic feet of residue; and 132.6 million cubic feet were harvested in 1994, with 85.6 million cubic feet of residue. Estimates for other years in the period from 1990 to 1996 were extrapolated from this data.

Table 4 summarizes trend estimates for removals in cubic feet, and Table 5 summarizes them in tons of dry matter. In accord with methodology from the *1990 Inventory*, the volume estimates were converted to tons of dry matter using a conversion factor of .016 tons dry matter per cubic foot as follows:

[7] USDA/NCFES, *Residential Fuelwood Production and Sources from Roundwood in Missouri, 1987*, 1991, p. 2.

[8] USDA/NCFES, *Timber Resources of Missouri*, 1994 and 1997 (draft).

Table 4 - Estimated volume of Missouri timber removals (cubic feet) in 1991-96

Units: 1,000 Cubic Feet

	1991	1992	1993	1994	1995	1996
Roundwood	121,400	125,133	128,867	132,600	136,333	140,067
Residue	67,600	73,608	79,615	85,623	86,995	0
Fuelwood	72,996	73,494	74,099	74,726	75,357	75,656
Total	***261,996***	***272,235***	***282,581***	***292,949***	***298,685***	

Table 5 - Estimated Missouri timber removals (tons of dry matter) in 1991-96

Units: 1,000 Tons Dry Matter

	1991	1992	1993	1994	1995	1996
Roundwood	1,942	2,002	2,062	2,122	2,181	2,241
Residue	1,082	1,178	1,274	1,370	1,392	1,413
Fuelwood	1,168	1,176	1,186	1,196	1,206	1,211
Total	***4,192***	***4,356***	***4,521***	***4,687***	***4,779***	***4,865***

Table 6 - Estimated sequestration offset due to Missouri timber removals in 1991-96

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1991	1992	1993	1994	1995	1996
Roundwood	3,547	3,656	3,765	3,874	3,983	4,092
Residue	1,975	2,151	2,326	2,502	2,542	2,580
Fuelwood	2,133	2,147	2,165	2,183	2,202	2,210
Total	***7,654***	***7,954***	***8,256***	***8,559***	***8,726***	***8,883***

The commercial roundwood harvest between 1996 and 2015 was projected based on scenarios from the NCFES publication *Missouri's Forest Resources, 1989: An Analysis*. *Forest Resources* presents two scenarios: a low-removals scenario that projects 213 million cubic feet of commercial roundwood removals in 2019 and a high-removals scenario that projects 266 million cubic feet of removals. According to NCFES staff, these projections are reasonable and provide the best available estimate at this time. Values for years between 1996 and 2015 were extrapolated based on average linear growth rate.

Residue between 1996 and 2015 was projected based on the assumption that harvest efficiency — the ratio of commercial roundwood to roundwood plus residue — equaled 61 percent in 1994 and would increase to 67 percent in 2015. The value of residue for intervening years between 1996 and 2015 was extrapolated.

The following tables summarize projection estimates for midpoint estimates of removals in cubic feet and in tons of dry matter, and the resulting estimates of offset CO_2 sequestration. The coefficients and conversion factors are identical with those used to estimate trends, and an identical methodology was used to estimate removals for the low and high harvest scenarios.

Table 7 - Midpoint estimate of volume of Missouri timber removals (cubic feet) in 1991-96

Units: 1,000 Cubic Feet

	1996	2000	2005	2010	2015
Roundwood	140,067	157,359	178,975	200,591	222,207
Residue	88,319	94,578	101,229	106,656	110,937
Fuelwood	75,656	76,855	78,336	79,865	81,434
Total	***304,042***	***328,793***	***358,541***	***387,112***	***414,578***

Table 8 - Midpoint estimate of tonnage of Missouri timber removal in 1991-96

Units: 1,000 Tons Dry Matter

	1996	2000	2005	2010	2015
Roundwood	2,241	2,518	2,864	3,209	3,555
Residue	1,413	1,513	1,620	1,706	1,775
Fuelwood	1,211	1,230	1,253	1,278	1,303
Total	***4,865***	***5,261***	***5,737***	***6,194***	***6,633***

Table 9 - Projected midpoint sequestration offset due to Missouri timber removals, 1996-2015

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1996	2000	2005	2010	2015
Roundwood	4,092	4,597	5,229	5,860	6,492
Residue	2,580	2,763	2,958	3,116	3,241
Fuelwood	2,210	2,245	2,289	2,333	2,379
Total	***8,883***	***9,606***	***10,475***	***11,310***	***12,112***

Section 3: Estimates of the impact of biomass removals on carbon sequestration from forest growth in Missouri

As discussed previously, the *State Workbook* endorses a simple method to account for carbon emissions from harvested wood, described here as the "immediate emissions method." This is one of two alternative methodologies recognized by the Intergovernmental Panel on Climate Change (IPCC), which serves as the international forum for developing guidelines on methodology for greenhouse gas inventories. The two alternative methods to account for carbon emissions from harvested wood may be described as follows:[9]

1) the ***carbon pools*** method, which accounts for the variable rate of decay of harvested wood according to its disposition (e.g., product pool, landfill, combustion), or

2) the ***immediate emissions*** method, which assumes that all of the harvested wood replaces wood products that decay in the inventory year so that the amount of carbon in annual harvests equals annual emissions from harvests. The IPCC guidelines refer to this as "the recommended default assumption … for initial calculations."[10]

Previous sections of this chapter make two key assumptions: 1) that biomass in Missouri forests will continue to increase at its historic rate of 3 percent per year; and 2) that the amount of carbon in annual forest harvests equals annual emissions from harvests. These assumptions, combined with a projected increase in forest harvest through 2015, lead to the report's conclusion that net annual sequestration from Missouri forests will decline through that year. In other words, the report projects that total carbon stored in Missouri forests will continue to increase, but the amount of carbon added each year will slowly decline.

The choice of methodology requires discussion because the carbon pools method is theoretically superior to the immediate emissions method. Other things being equal, use of the carbon pools method would probably increase the study's estimate of net CO_2 sequestration from Missouri forests and forest products. However, use of the carbon pools method is impractical for this study.

The following discussion summarizes the use of the carbon pools method in several recent studies, describes the obstacles to its use in this study and discusses how the choice of methodology affects the quality of the estimate.

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[9] IPCC/UNEP/OECD/IEA (1997) *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories,* Paris: Intergovernmental Panel on Climate Change, United Nations Environment Program, Organization for Economic Co-Operation and Development, International Energy Agency. Chapter 5, Box 5, p. 19. The treatment of harvested wood has continued to be a controversial topic among member governments of IPCC; some issues may be resolved by an IPCC Expert Group Meeting scheduled in Dakar, Senegal during 5/4/98-5/9/98. Personal communication, Wiley Barbour, USEPA, 5/7/98.

[10] *ibid.*, p. 19.

Section 4: Use of the "carbon pools" method in current national and global studies

Analyses using the "carbon pools" method treat growing forests as one of several related "carbon pools" that sequester carbon which might otherwise enter the atmosphere as CO_2. From this viewpoint, when biomass is removed from the forest pool, a portion of the carbon continues to be sequestered in these other carbon pools in the form of durable wood products or landfilled product.

This "carbon pools" method has been adopted by several recent studies of the role of forests and wood products in the carbon cycle at a national or global level. For example, a current study by Kenneth Skog concludes that:

> Since 1910, an estimated 2.7 Pg (petagrams; $\times 10^9$ metric tons) of carbon have accumulated and currently reside in wood and paper products in use and in dumps and landfills, including net imports. This is notable compared with the current inventory of carbon in forest trees (13.8 Pg) and forest soils (24.7 Pg). On a yearly basis, net sequestration of carbon in U.S. wood and paper products … is projected to increase … while net additions (sequestration) in forests is projected to decrease … Net sequestration is increasing in products and landfills because of an increase in wood consumption and a decrease in decay in landfills compared with phased-out dumps.[11]

A 1996 study by Heath, Birdsey, Row and Plantinga comes to similar conclusions.[12]

USEPA also adopts this approach in its current (1998) inventory of national greenhouse gas emissions,[13] as follows:

> Timber harvests may not always result in an immediate flux of carbon to the atmosphere. Harvesting, in effect, transfers carbon from one of the "forest pools" to a "product pool." Once in a product pool, the carbon is emitted over time as CO_2 through either combustion or decay of the product. The rate of emission varies considerably among different product pools. For example, if timber is harvested for energy use, combustion results in an immediate release of carbon. Conversely, if timber is harvested and subsequently used as lumber in a house, it may be many decades or even centuries before the lumber is allowed to decay and carbon is released to the atmosphere. Discarded wood and wood products may be stored in landfills for years or decades before they decay.

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[11] Kenneth E. Skog and Geri Nicholson, "Carbon Cycling through Wood Products: The Role of Wood and Paper Products in Carbon Sequestration," revised April 1998, prepared for publication in *Forest Products Journal*, p. 1.

[12] Heath, L.S., R.A. Birdsey, C. Row, and A.J. Plantinga. 1996. "Carbon pools and fluxes in U.S. forest products." p. 271–278. In Proceedings of the NATO advanced research workshop. *"The role of global forest ecosystems and forest resource management in the global cycle."* Banff, Canada. 12–14 Sept. 1994. NATO ASI Series I: Global Environmental Change. Vol. 40. Springer-Verlag, Berlin. Birdsey is the most recognized expert in this field. Skog's paper, *op.cit.*, includes a detailed comparison of the two studies' assumptions, methods and conclusions.

[13] USEPA, Office of Planning, Policy and Evaluation, *Inventory of U.S. Greenhouse Gas Emissions and Sinks*, 3/18/98 draft posted for comment at http://www.epa.gov/globalwarming/inventory/1998-inv.html.

> Because most of the timber that is harvested from U.S. forests is used in wood products and much of the discarded wood products are disposed of by landfilling rather than incineration, significant quantities of harvested carbon are transferred to long-term storage pools rather than being released to the atmosphere. The size of these long-term carbon storage pools has also increased steadily over the last century. [14]

These studies use models that allocate harvested carbon to disposition categories (products, landfills, energy use and emissions) and track the accumulation of carbon in different disposition categories over time. For the studies cited in the this section, Skog used the WOODCARB model. Heath and Birdsey used the HARVCARB model and USEPA is using the HARVCARB model.

The carbon pools methodology is theoretically appealing but demands substantial data and resources. The following section describes the barriers to implementing the approach in state-level studies such as the draft report.

[14] *op. cit.*, pp. 87, 88.

Section 5: Impracticality of the "carbon pools" method at the state level

USEPA's *State Workbook*, the methodological guidebook for state greenhouse gas inventories, instructs states' partners to assume that, when biomass is removed from forests, all carbon contained in the biomass is emitted to the atmosphere at the time of removal. [15] The *State Workbook* states that this is a "legitimate, conservative assumption for initial calculations," citing the following reasons:

1) The measurement process is complicated by the fact that new products from current timber harvests frequently replace existing product stocks[16]; and

2) Although the long-term storage of carbon in wood products and landfilled wood is accounted for in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1996* (USEPA, 1998), this kind of carbon storage cannot be easily estimated on a state-by-state basis because the processes of harvesting wood, manufacturing wood products, and disposing of wood and wood products often cross state lines.

In order to account for replacements, the studies cited in the previous section use models that allocate harvested carbon to disposition categories. However, these models have been created and calibrated only at the global or national level. State-level versions of these models do not exist and are probably impractical. Kenneth Skog, a current authority in the field, has stated that he "can't imagine states doing [the analysis] individually." [17]

A major barrier to building such a state model is that it would require building a series of disposition matrices to account for the disposition of forest harvest and wood products to the various carbon pools at the state level. Data required to build these matrices would include:

a) the disposition of the forest harvest to end uses;

b) the disposition of the end-use products to new stock versus displacement of existing product stock;

c) the disposition of the displaced stock to combustion or other pools such as recycling or landfills; and

d) the disposition over time of end-use products to landfills, combustion or emissions.

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[15] USEPA is considering a revision of the methodology recommended in the *State Workbook* but recognizes the impracticality of requiring each state to do "carbon pools" analysis. A possible solution would be for USEPA to analyze carbon pools at a national level and supply default values to states. However, this solution is not currently funded. Personal communication, Wiley Barbour, USEPA,.4/30/98.

[16] According to IPCC methodological guidelines, in order to include storage of carbon in forest products in its state inventory, Missouri would at minimum need to demonstrate "that existing stocks of long-term forest products are, in fact, increasing." IPCC/UNEP/OECD/IEA, ibid., p. 19.

[17] Personal communication, 4/30/98.

State-level data necessary to build these disposition matrices does not exist. The only available data covers the disposition of forest harvest to primary product categories, such as "saw logs." This data is available from periodic surveys of the disposition of trees and tree material harvested in Missouri by the USDA Forest Service.[18] However, the USDA surveys do not track forest harvest through secondary processing into end uses for the final market, such as pallets or grade lumber.[19]

The second issue cited in the *State Workbook* is that "the processes of harvesting wood, manufacturing wood products, and disposing of wood and wood products often cross state lines." Most of the forest products harvested in Missouri do undergo primary processing in the state.[20] However, much of the product then leaves the state for secondary processing into consumer end products. In addition, many wood-based consumer products manufactured in Missouri leave the state, and many products containing wood are imported into the state. [21]

Missouri is probably a net exporter of saw wood, although construction relies predominantly on imported soft wood products. [22] On the other hand, Missouri is a net importer of pulp, although this could change if so-called pulp mills become widely established in Missouri. Most of the product of pulp mills would be exported for manufacture into paper at plants located outside the state.

Data to track these product movements across state lines is currently unavailable. Furthermore, in the absence of USEPA methodological guidance, a state-level effort to account for product movements across state lines is inadvisable since there is no guarantee that the resulting analysis could be compared to analyses by other states.

There appears to be no practical way to resolve these obstacles to accounting for the disposition of forest harvest into carbon pools. Therefore, this study follows the guidance of the USEPA *State Workbook* and adopts the "immediate emissions" method of accounting for carbon emissions from harvested wood.

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[18] USDA Forest Service, North Central Forest Experiment Station, *Missouri Timber Industry —An Assessment of Timber Product and Use*, various years.

[19] Personal communication, Shelby Jones, Mo. Dept. of Conservation, 4/30/98.

[20] Personal communication, Ron Hackett, USDA Forest Service, North Central Forest Experiment Station, 4/30/98.

[21] Shelby Jones, *op.cit*.

[22] Shelby Jones, *op.cit*.

Section 6: The effect of methodology choice on estimates in the draft report

Other things being equal, use of the immediate emissions method leads to a lower estimate of net sequestration from Missouri forests and forest products than would an estimate generated by the carbon pools method.

Most of Missouri's roundwood harvest goes into primary product categories such as saw logs, cooperage logs, veneer logs and miscellaneous categories. Much of the wood from this primary processing probably goes into secondary manufactured products, which last for a number of years, and then into landfills, where it may be sequestered for many more years.

The carbon contained in harvest residues appears less likely to be sequestered in product and landfill pools for long periods of time. About 85 percent of Missouri's charcoal and most of its pulp derive from mill residue rather than roundwood. Most charcoal is manufactured into briquettes for combustion, although some is manufactured into specialty products for the chemical industry. Pulp from harvest residues as well as the limited amount of pulp currently derived from Missouri's roundwood harvest goes into paper products. In general, paper products are subject to more rapid decay than solid wood. Section 4 discusses factors that can affect the rate of decay of paper products.

In order to quantify the difference in estimates produced using the two methodologies, it would be necessary to estimate product disposition matrices such as those described in Section 2. Given the nature of Missouri's saw wood-based timber economy, the difference could be significant. It seems likely that a substantial percentage of the carbon from harvest remains sequestered for long periods in the wood-product carbon pool.

In evaluating the draft report's estimate of net sequestration from forest growth and forest products, one should take into account that methodology in this area is unsettled[23] and that some necessary data sources are underdeveloped. Consequently, the estimate offered in this report is subject to several sources of error that might lead to an underestimate or overestimate of net sequestration. Moreover, these different sources of error may offset each other.

Possible sources of an underestimate of net sequestration include:

1) The use of the immediate emissions method for estimating the impact of removals.

2) The assumption that the growth rate of forest biomass will remain constant at 3 percent. This growth rate reflects past management practices. Management practices could change in ways that would increase the growth rate. As sensitivity analysis in the report indicates, a 1 percent increase in forest growth rate would lead to a 33 percent increase in sequestration, other things being equal.[24]

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[23] USEPA State and Local Climate Change Outreach Program staff have that methodology for estimates of emissions from forest and land use changes is problematic and under revision.

[24] Chapter 5, Table 46, p. 53.

a) Findings from forest inventories indicate the quality of the current forest sites will support growth rates greater than the historic 3 percent rate.[25]

b) Forest management practices could change in response to an increase in Missouri's pulpwood harvest, for example through the widespread introduction of "chip mills." A preliminary analysis provided by the Missouri Department of Conservation[26] suggests that an increase in pulpwood harvest would favor management practices that tend to increase forest growth rate. According to this analysis, increased pulpwood harvest leads to removal of materials that impede growth rate (small diameter and small stem trees, understory species). When these materials are removed, the remaining timber grows faster. In addition, pulpwood harvesting tends to result in even-age management systems that result in more wood fiber production than uneven age systems associated with sawlog production. The analysis is based in part on observation of the impact of increased pulpwood harvest on timber growth rates in the Southeastern states.[27]

Possible sources of an overestimate of net sequestration include:

1) Forest growth rate could decrease as well as increase. As the draft report notes, forest growth rate could decrease due to maturation, such as has occurred in a number of Northeastern states. Forest growth rate could also decrease if landowners were to move away from sustainable forest management practices. A 1 percent decrease in forest growth rate would decrease sequestration by about 33 percent.

2) Although an increase in pulpwood harvest could increase biomass growth rate, it could decrease the average storage duration of carbon derived from Missouri forest harvest. In general, the paper products manufactured from pulpwood harvest are subject to more rapid decay than the solid wood products produced from Missouri's traditional saw wood timber economy. However, the length of time that the carbon in paper is sequestered in product and landfill pools can vary depending on several factors:

   a) Recycling can extend the period during which the carbon is stored in a product pool.

   b) Paper with high lignin content decays slowly in landfills.

   c) Some studies indicate that paper in modern landfills may escape decay for very long periods of time.[28]

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[25] Shelby Jones, personal communication, 4/30/98.

[26] Shelby Jones, ibid.

[27] A premise of this analysis is that landowners and loggers would make a long-term commitment to managing forested acres in a sustainable manner. A St. Louis Post Dispatch article, "Paper Companies Turn to Missouri - And Its Trees," discusses Department of Conservation goals of assisting landowners in practices such as stand thinning and selective harvesting. (Sunday, Sept. 21, 1997, p. 8.)

[28] J. A. Micales & K. E. Skog, See *The Decomposition of Forest Products in Landfills*, International Biodeterioration & Biodegradation Vol. 39, No. 2–3 (1997), 145–158.

3) Finally, the harvest growth rate projected by the study may be low. The only available projection of forest harvest appears in a *Forest Resource* study completed in 1989.[29] This source projects a linear growth curve for forest removals. Since 1989, the growth curve for forest removals has grown steeper, following a curvilinear growth pattern. Preliminary returns from a 1997 *Forest Resource* study indicate the faster growth rate established in the first half of the decade will probably continue. After completion of the 1997 *Forest Resource* study, four data points will be available, providing the basis for more reliable projections.[30]

[29] USDA Forest Service, North Central Forest Experiment Station, *Missouri's Forest Resource, 1989: An Analysis*, 1989. This projection is discussed in Chapter 5, Part 5, Section 2 of this study.

[30] Shelby Jones, Personal communication, Missouri Dept. of Conservation, 4/30/98. The four data points are *Forest Resource* studies for 1989, 1991, 1994 and 1997.

Glossary

Glossary

Aerosol: Particulate material, other than water or ice, in the atmosphere.

Anaerobic fermentation: Fermentation that occurs under conditions where oxygen is not present. For example, methane emissions from landfills result from anaerobic fermentation of organic waste in the landfills.

Anthropogenic: Relating to the influence of human beings on nature. For instance, "anthropogenic" emissions of greenhouse gases are emissions resulting from human activities such as burning gasoline in motor vehicles or burning coal to generate electricity.

Anthropogenic emissions: Any emissions resulting from human activities.

Atmosphere: The envelope of air surrounding the Earth and bound to it by the planet's gravitational attraction.

Baseline forecast: A baseline forecast is used to outline future energy demand under a business-as-usual scenario and show where opportunities lie for energy savings and environmental improvement. A baseline forecast describes what would most likely happen if current trends continue and if no changes occur in state and national energy policy. Other scenarios, incorporating new policies, new technologies, alternative economic conditions and other assumptions, may be contrasted to this baseline case.

Baseload: A baseload plant is normally operated to provide all or part of the minimum electric load of a utility system. Baseload units are generally run continuously to produce electricity at a constant rate, allowing for planned maintenance and forced outages.

Biomass: Organic matter that is available on a renewable basis including forest residues, agricultural crops and wastes, wood and wood waste, animal wastes, livestock operation residue, and aquatic plants. Useful energy can be derived from the direct combustion of biomass or flammable gases derived from biomass for generation of electricity, mechanical power, or industrial process heat. In this report, biomass usually refers to wood and wood waste.

British thermal unit (Btu): The amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. It is commonly used as a measurement for the energy content of different fuels or energy sources. One kWh equals 3,412 BTU.

Carbon cycle: The continual circulation of carbon between the atmosphere, soil and rocks, oceans and living plants and animals. Carbon, a chemical element, is a constituent of all living matter. One form in which carbon resides in the atmosphere is carbon dioxide ($C0_2$).

Carbon reservoir or sink: A physical site within the carbon cycle where carbon is stored, such as the atmosphere, oceans, Earth's vegetation and soils (in forests, for example), and fossil fuel deposits.

Carbon source and carbon sink: Terms used to describe the exchange of carbon in the carbon cycle. For instance, when wood is burned, producing $C0_2$, the carbon "source" is biomass and the "sink" is the atmosphere.

Carbon dioxide ($C0_2$): A molecule made up of one atom of carbon and two atoms of oxygen. Sources include respiration (breathing) in animals and the burning of organic matter or fossil fuels. Plants use CO_2 in the process of photosynthesis.

Carbon monoxide (CO): A molecule comprised of one atom of carbon and one atom of oxygen. An odorless, invisible gas, it is created when carbon-containing fuels are burned incompletely. It is not a greenhouse gas, but it is short-lived and often transforms into $C0_2$. It has harmful effects on human health.

Chlorofluorocarbons (CFCs): A family of inert non-toxic and easily liquefied chemicals used in refrigeration, air conditioning, packaging, and insulation or as solvents or aerosol propellants. Because they are not destroyed in the lower atmosphere, they drift into the upper atmosphere where their chlorine components destroy ozone.

Climate change: Long-term fluctuations in temperature, precipitation, wind and all other aspects of the climate. Over thousands of years, climate change occurs naturally. Controversy centers over whether humans are now causing climate to change over relatively short periods of time such as one to two human generations.

Coalification: The geologic process which results in the formation of coal.

Combined cycle plant: A combined cycle plant utilizes the most efficient large-scale thermal electric generation technology available today. Combined cycle technology uses the excess heat produced by a combustion turbine to power an additional turbine that produces even more electricity. Using the waste heat from the combustion turbine to produce more electricity dramatically improves the efficiency of the plant. Nearly all commercially available combined cycle plants and advanced combustion turbines are fired by natural gas. Compared to conventional oil- or coal-fired generators, they require less fuel and have fewer emissions per unit of electricity produced.

Demand-side management: The planning, implementation, and monitoring of electric utility activities designed to reduce customer use of electricity. Regulated utilities that are required to service a specific customer base have pursued DSM as an approach to meeting load requirements when it is more cost-effective than other available supply side resources such as construction of a new power plant or wholesale purchase of power.

Enteric fermentation: Fermentation that occurs in the intestines. For example, methane emissions produced as part of the normal digestive processes of ruminant animals is referred to as "enteric fermentation."

Flaring: Combusting a gas such as methane at the point at which it would otherwise be released into the atmosphere; as a result of flaring, the gas does not enter the atmosphere although the byproducts of combustion may enter the atmosphere.

Fossil fuels: Fuel resources (coal, oil and natural gas) embedded in the earth's crust that were created from the bodies of animals and plants by geologic processes lasting millions of years. Because they were created from organic matter, they contain carbon. When they are burned as fuels, this carbon is released as CO_2.

Global Warming Potential (GWP): The concept of the Global Warming Potential has been developed for policy-makers as a measure of the possible warming effect on the surface-troposphere system arising from the emissions of each gas relative to $C0_2$.

Global warming: A popular term for climate change that may result from anthropogenic emissions of greenhouse gases. In the "global warming" scenario, temperature around the globe rises several degrees in a short period of time.

Greenhouse effect: Describes the role of greenhouse gases in trapping heat, thereby keeping the Earth's surface warm enough to sustain life as we know it. Scientists agree that the greenhouse effect is real. Controversy centers over the degree to which human activities are increasing concentrations of greenhouse gases in the atmosphere, thereby increasing the amount of heat trapped and affecting climate.

Greenhouse gases: Those gases--such as carbon dioxide, methane, nitrous oxide and ozone--that let radiation from the sun reach the earth but trap outgoing heat. Their action is analogous to that of glass in a greenhouse.

Hydrochlorofluorocarbons (HCFCs): HCFCs are essentially chlorofluorocarbons (CFCs) that include one or more hydrogen atoms. The presence of hydrogen makes the resulting compounds less stable, and as a result they have shorter atmospheric lifetimes than CFCs and are less likely to drift into the upper atmosphere where their chlorine components would destroy ozone. They are popular interim substitutes for CFCs, but international agreements have slated HCFCs for elimination by 2030. Like CFCs, HCFCs are potent greenhouse gases; however, they have weaker indirect cooling effects than CFCs.

Hydrofluorocarbons (HFCs): HFCs are essentially hydrochlorofluorocarbons (HCFCs) without the chlorine. Because they do not destroy ozone, they are widely used as substitutes for CFCs and HCFCs. Although HFCs do not deplete ozone, they are powerful greenhouse gases and lack the indirect cooling effects of CFCs and HCFCs. For example, HFC-23 has a GWP of 10,000.

kiloWatthour (kWh): A unit of energy equivalent to using one kiloWatt of electricity for one hour, equal to 3,412 BTUs.

Methane (CH_4): A molecule made up of one atom of carbon and four atoms of hydrogen. Methane is a greenhouse gas which contributes about 10 percent of Missouri emissions and 18 percent of global emissions. Anthropogenic sources of methane include wetland rice cultivation, enteric fermentation by domestic livestock, anaerobic fermentation of organic wastes, coal mining, biomass burning, and the production, transportation, and distribution of natural gas.

Nitrogen Oxides: (NO~): NO~ refers collectively to NO, a molecule made up of one atom of nitrogen and one atom of oxygen, and NO_2, a molecule made up of one atom of nitrogen and two atoms of oxygen. NO~ is created in lighting, in natural fires, in fossil-fuel combustion, and in the stratosphere from N_20. It plays an important role in the global warming process due to its contribution to the formation of ozone (0_3).

Nitrous Oxide (N_20): A molecule made up of two atoms of nitrogen and one atom of oxygen. Nitrous oxide is a greenhouse gas which contributes about two percent of Missouri emissions and five percent of global emissions. Nitrous oxide is produced from a wide variety of biological and anthropogenic including application of nitrogenous fertilizers, consumption of fuel and various production processes such as manufacture of nitric acid.

Nonmethane Volatile Organic Compounds (NMVOCs): NMVOCs are frequently divided into methane and non-methane VOCs (see definition of Volatile Organic Compounds). NMVOCs include compounds such as propane, butane and ethane.

Ozone (0_3): A molecule comprised of three atoms of oxygen. Ozone (0_3) exists in both the lower atmosphere (troposphere) and upper atmosphere (stratosphere). In the troposphere, ozone is an ingredient of smog. However, in the stratosphere, it provides a protective layer that shields the Earth from ultraviolet radiation.

Ozone depletion: Scientists generally agree that certain manufactured chemicals such as chorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) remove ozone from the stratosphere where it normally provides a protective shield from ultraviolet radiation. Collectively, these chemicals are called Ozone Depleting Compounds (ODCs). The removal of ozone is called "ozone depletion" and is a separate policy issue that should not be confused with "climate change" or "global warming." The two issues are often discussed together because several ODCs are also potent greenhouse gases.

Perfluorinated Carbons (PFCs): PFCs are powerful greenhouse gases whose molecules consist of carbon and fluorine atoms. PFCs are emitted during electrolytic reduction of alumina in the primary reduction process.

Sequestered carbon: Carbon that is "trapped" in some part of the carbon cycle other than the atmosphere. For example, the carbon content of coal is sequestered until the coal is burned and carbon returns to the atmosphere as $C0_2$. Plants sequester carbon when they convert $C0_2$ to plant material.

Sequestration: A process by which carbon dioxide is removed from the atmosphere and isolated for some period in a carbon reservoir such as forest biomass or wood products.

Short Tons Carbon Dioxide Equivalent (STCDE): Emissions of methane, nitrous oxide and PFCs are reported in this unit of measurement. The derivation of this unit of common measure is based on Global Warming Potential (GWP) factors for the different gases.

Stratosphere: Region of the upper atmosphere extending upward from an altitude between six and nine miles to an altitude of about 30 miles.

Trace Gas: A minor constituent of the atmosphere. The most important trace gases contributing to the greenhouse effect include water vapor, carbon dioxide, ozone, methane, ammonia, nitric acid, nitrous oxide, and sulfur dioxide.

Troposphere: The inner layer of the atmosphere, extending upward to an altitude of six to nine miles. Within the troposphere, there is normally a steady decrease of temperature with increasing altitude. Nearly all clouds form and weather conditions occur within the troposphere.

Utility Restructuring: The reconfiguration of the vertically integrated electric utility in the context of electric utility deregulation. Reconfiguration refers to separation of the various utility functions such as generation, transmission, distribution and customer services into individually operated and owned entities. Electric utility deregulation refers to the modification or elimination of regulation from the previously regulated utility industry.

Volatile Organic Compounds (VOCs): Volatile organic compounds, along with nitrogen oxides, are participants in atmospheric chemical and physical processes that result in the formation of ozone and other photochemical oxidants. The largest sources of reactive VOC emissions are transportation sources and industrial processes. Miscellaneous sources, primarily forest wildfires and non-industrial consumption of organic solvents, also contribute significantly to total VOC emissions.

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An earlier draft of this report was distributed for review to the following agencies and individuals in April, 1999.

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